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

FORM 10-K

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

For the fiscal year ended December 31, 2019

OR

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

For the transition period from ____________ to ____________

Commission file number 001-37907

EXTRACTION OIL & GAS, INC.

(Exact name of registrant as specified in its charter)

Delaware	**46-1473923**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
370 17th Street, Suite 5300 **Denver Colorado**	**80202**
(Address of principal executive offices)	(Zip Code)

(720) 557-8300

(Registrant's telephone number, including area code)

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock, par value $0.01	**XOG**	**NASDAQ Global Select Market**

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No ☐

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

Large accelerated filer	☐	Accelerated Filer	x
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $334 million as of June 30, 2019, (based on the last sale price of such stock as quoted on the NASDAQ Global Select Market).

The total number of shares of common stock, par value $0.01 per share, outstanding as of March 9, 2020 was 137,786,612.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2020 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates, are incorporated by reference into Part III of this Annual Report on Form 10-K.

EXTRACTION OIL & GAS, INC.
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains "forward-looking statements." All statements, other than statements of historical facts, included or incorporated by reference herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "'potential," " should," "could," and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in this report and our other filings with the Securities and Exchange Commission for further information on risk and uncertainties that could affect our business, financial condition, results of operations and cash flows. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- federal and state regulations and laws;
- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- risks and restrictions related to our debt agreements;
- our ability to use derivative instruments to manage commodity price risk;
- realized oil, natural gas and NGL prices;
- a decline in oil, natural gas and NGL production, and the impact of general economic conditions on the demand for oil, natural gas and NGL and the availability of capital;
- asset impairments from commodity price declines;
- the willingness of the Organization of Petroleum Exporting Countries (“OPEC”) to set and maintain production levels;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- geographical concentration of our operations;
- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;
- drilling operations associated with the employment of horizontal drilling techniques, and adverse weather and environmental conditions;
- limited control over non-operated properties;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;
- risks relating to managing our growth, particularly in connection with the integration of significant acquisitions;
- impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
- risks associated with a material weakness in our internal control over financial reporting;
- changes in tax laws;
- effects of competition;
- the outbreak of communicable diseases such as coronavirus; and
- seasonal weather conditions.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas, and NGL that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGL that are ultimately recovered.

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Annual Report. Except as required by law, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

GLOSSARY OF OIL AND GAS TERMS

Unless indicated otherwise or the context otherwise requires, references in this Annual Report on Form 10-K ("Annual Report") to the "Company," "Extraction," "us," "we," "our," or "ours" or like terms refer to Extraction Oil & Gas, Inc., together with its consolidated subsidiaries.

The terms defined in this section are used throughout this Annual Report:

"Bbl" means one stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

"Bbl/d" means Bbl per day.

"BOE" means barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"BOE/d" means BOE per day.

"Btu" means one British thermal unit – a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

"CIG" means Colorado Interstate Gas, which is calculated as NYMEX Henry Hub index price less the Rocky Mountains (CIGC) Inside FERC fixed price.

"Completion" means the installation of permanent equipment for the production of oil or natural gas.

"Dekatherms" means a unit of energy used primarily to measure natural gas equal to 1,000,000 Btus (MMBtu).

"Developed acreage" means the number of acres that are allocated or assignable to producing wells or wells capable of production.

"Development well" means a well drilled to a known producing formation in a previously discovered field, usually offsetting a producing well on the same or an adjacent oil and natural gas lease.

"Exploratory well" means a well drilled either (a) in search of a new and as yet undiscovered pool of oil or gas or (b) with the hope of significantly extending the limits of a pool already developed (also known as a "wildcat well").

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

"Fracturing" or "hydraulic fracturing" means a procedure to stimulate production by forcing a mixture of fluid and proppant (usually sand) into the formation under high pressure. This creates artificial fractures in the reservoir rock, which increases effective permeability and porosity.

"Gas" or "Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain liquids.

"Gross Acres" or "Gross Wells" means the total acres or wells, as the case may be, in which we have a working interest.

"Henry Hub" means Henry Hub index. Natural gas distribution point where prices are set for natural gas futures contracts traded on the NYMEX.

"Horizontal drilling" or "horizontal well" means a wellbore that is drilled laterally.

"Leases" means full or partial interests in oil or gas properties authorizing the owner of the lease to drill for, produce and sell oil and natural gas in exchange for any or all of rental, bonus and royalty payments. Leases are generally acquired from private landowners (fee leases) and from federal and state governments on acreage held by them.

"MBbl" One thousand barrels of oil, condensate or NGL.

"MBoe" One thousand barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

"Mcf" is an abbreviation for "1,000 cubic feet," which is a unit of measurement of volume for natural gas.

"MMBtu" One million Btus.

"MMcf" is an abbreviation for "1,000,000 cubic feet," which is a unit of measurement of volume for natural gas.

"Net Acres" or "Net Wells" is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

"Net revenue interest" means all of the working interests less all royalties, overriding royalties, non-participating royalties, net profits interest or similar burdens on or measured by production from oil and natural gas.

"NGL" means natural gas liquids.

"NYMEX" means New York Mercantile Exchange.

"Operator" means the individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

"Overriding royalty" means an interest in the gross revenues or production over and above the landowner's royalty carved out of the working interest and also unencumbered with any expenses of operation, development, or maintenance.

"Productive well" means a well that is producing oil or natural gas or that is capable of production.

"Prospect" means a geological area which is believed to have the potential for oil and natural gas production.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves" means 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.

"Proved undeveloped reserves" means 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 of 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 value" means the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

"Reasonable certainty" means a high degree of confidence that the reserves quantities will be recovered, when a deterministic method is used. A high degree of confidence exists if the reserves 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.

"Recompletion" means the completion for production from an existing wellbore in a formation other than that in which the well has previously been completed.

"Reserve life" represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

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

"Royalty" means the share paid to the owner of mineral rights, expressed as a percentage of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing and operating of the affected well.

"Royalty interest" means an interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production, free of costs of exploration, development and production operations.

"SEC" means the Securities and Exchange Commission.

"SEC pricing" means the price per Bbl for oil or per MMBtu for natural gas as calculated from the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months.

"Seismic data" means an exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation.

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

"Undeveloped acreage" means lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether or not such acreage contains proved reserves.

"Undeveloped leasehold acreage" means the leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains estimated net proved reserves.

"Unit" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Wattenberg Field" means the Greater Wattenberg Area within the Denver-Julesburg Basin of Colorado as defined by the Colorado Oil and Gas Conservation Commission, which are the lands from and including Townships 2 South to 7 North and Ranges 61 West to 69 West, Six Principal Median.

"Working interest" means an interest in an oil and natural gas lease entitling the holder at its expense to conduct drilling and production operations on the leased property and to receive the net revenues attributable to such interest, after deducting the landowner's royalty, any overriding royalties, production costs, taxes and other costs.

"WTI" means the price of West Texas Intermediate oil on the NYMEX.

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

Company Overview

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, as well as the construction and support of midstream assets to gather and process crude oil and gas production in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado. The Wattenberg Field has been producing since the 1970s and is a premier North American oil and natural gas basin characterized by high recoveries relative to drilling and completion costs, high initial production rates, long reserve life and multiple stacked producing horizons. We have assembled, as of December 31, 2019, approximately 169,900 net acres of large, contiguous acreage blocks in some of the most productive areas of the DJ Basin, indicated by the results of our horizontal drilling program and the results of offset operators, which we refer to as the "Core DJ Basin." We believe our acreage in the Core DJ Basin has been significantly delineated by our own drilling success and by the success of offset operators, providing confidence that our inventory is relatively low-risk, repeatable and will continue to generate economic returns. Toward the end of the third quarter and into the fourth quarter of 2019, management elected to shift corporate strategy from one of maximizing production and reserve growth to one focused on cash flow and reducing debt while improving our liquidity.

We were founded in November 2012 with the objective of becoming a Wattenberg focused company with acreage that has (i) low development risk as a result of being within the vicinity of other successful wells drilled by other oil and gas companies, (ii) limited vertical well drainage relative to offset operators in a field with significant historical vertical activity, and (iii) higher oil content than was traditionally targeted when many operators first established their position in the field seeking natural gas production. We believe these characteristics enhance our horizontal production capabilities, recoveries and economic results. Our drilling economics are further enhanced by our ability to drill longer laterals due to our large contiguous acreage position, which our management team built through organic leasing and a series of strategic acquisitions. We operated 96% of our horizontal production for the year ended December 31, 2019 and maintain control of a large majority of our drilling inventory. In addition, we proactively seek to secure the necessary midstream and operational infrastructure to keep pace with our production growth.

For the year ended December 31, 2019, we drilled 107 gross wells with an average lateral length of 2.0 miles and completed 119 gross wells with an average lateral length of 1.9 miles, all of which were horizontal wells in the DJ Basin. We are currently running a full time two-rig program and our 2020 capital budget anticipates a one to two operated drilling rig program. Our average net daily production during the fourth quarter and year ended December 31, 2019 was 111,077 BOE/d and 88,728 BOE/d, respectively.

The following table provides summary information regarding our proved reserves as of December 31, 2019, and our average net daily production for the year ended December 31, 2019.

Estimated Total Proved Reserves(1)								
Oil (MBbls)	Natural Gas (MMcf)	NGL (MBbls)	Total (MBoe)	% Oil	% Liquids(2)	% Developed	Average Net Production (BOE/d)(1)(3)	R/P Ratio (Years)(4)
91,459	580,089	66,009	254,149	36 %	62 %	56 %	88,728	7.8

(1) Includes de minimis reserves and production attributable to properties in our Other Rockies Area. Please see "—Other Properties."
(2) Includes both oil and NGL.
(3) Average net daily production. Consisted of approximately 48% oil, 33% natural gas and 19% NGL.
(4) Represents the number of years proved reserves would last assuming production continued at the average rate for the year ended December 31, 2019. Because production rates naturally decline over time, the R/P Ratio is not a useful estimate of how long properties should economically produce.

Our Properties

Core DJ Basin

Our current operations are located in the DJ Basin, primarily in the Wattenberg Field where we target the oil and liquids-weighted Niobrara and Codell formations. As of December 31, 2019, our position in the Core DJ Basin consisted of approximately 169,900 net acres.

Our estimated proved reserves at December 31, 2019 were 254.1 MMBoe. As of December 31, 2019, we had a total of 1,509 gross wells capable of producing, of which 961 were horizontal wells. The vertical wells we operate primarily serve to hold leases until we can drill more efficient horizontal wells on acreage we lease. Therefore, production from vertical wells does not represent a material amount of our current production and is anticipated to decline as a percentage of total production in the future as we drill more horizontal wells. Our average net daily production during the year ended December 31, 2019 was approximately 88,728 BOE/d. Our working interest for all wells capable of producing averages approximately 72% and our net revenue interest is approximately 59%.

We continue to expand our proved reserves in this area by drilling non-proved horizontal locations. As of December 31, 2019, we had an identified drilling inventory of approximately 228 gross (146 net) proved undeveloped horizontal drilling locations with varying lateral lengths on our acreage with average gross well costs of $5.4 million. During 2019, we drilled 107 gross operated horizontal wells and completed 119 gross operated horizontal wells.

Other Properties

We hold approximately 125,500 net acres outside of the Core DJ Basin, which we refer to as our "Other Rockies Area," that we believe is prospective for many of the same formations as our properties in the Core DJ Basin. As of December 31, 2019, there were de minimis proved reserves associated with this acreage.

Gathering Systems and Facilities

Elevation Midstream, LLC ("Elevation"), a Delaware limited liability company and an unrestricted subsidiary of ours, is focused on the construction of gathering systems and facilities operations to serve the development of our acreage in Hawkeye and Southwest Wattenberg areas. Midstream assets of Elevation are represented as the gathering systems and facilities line item within the consolidated balance sheets. In October 2019, Elevation commenced moving crude oil, natural gas and water through its newly constructed Badger central gathering facility. This facility enables Extraction and will enable others to efficiently transport crude oil and natural gas production along with water used during the completion process. The use of this gathering facility allows for the elimination of oil or water storage on the well pad site and reduces truck traffic, which minimizes the impact to the surrounding environment and communities. Revenues and operating expenses associated with the gathering systems and facilities operations are primarily derived from intersegment transactions for services provided to our exploration, development and production operations as well as third parties.

2020 Capital Budget

Our 2020 capital budget for the drilling and completion of operated and non-operated wells is approximately $425 million to $475 million, substantially all of which we intend to allocate to the Core DJ Basin. We expect to drill 86 gross operated wells, complete 86 gross operated wells and turn-in-line 92 gross operated wells. Our capital budget anticipates a one to two operated rig drilling program and excludes up to $50 million for Elevation, a portion of which will be funded by Extraction.

The amount and timing of these capital expenditures is within our control and subject to our management’s discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Recent Developments

Global Industry Downturn

In early March 2020, crude oil prices declined to below $40 per barrel for Brent crude as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand, which is related in part to the outbreaks in several countries, including the United States, of a highly transmissible and pathogenic coronavirus (“COVID-19”). We intend to manage our operations, including both operating expenses and capital expenditure levels, in view of the existing and expected pricing environment.

Senate Bill 19-181 "Protect Public Welfare Oil and Gas Operations"

In April 2019, Senate Bill 19-181 ("SB181") became law, increasing the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development in a reasonable manner and, in December 2019, Colorado's Air Quality Control Commission ("AQCC") adopted new rules targeting air emissions from upstream oil and gas operation. Among other things, SB181 (i) repeals a prior law restricting local government land use authority over oil and gas mineral extraction areas to areas designated by the Colorado Oil and Gas Conservation Commission ("COGCC"), (ii) directs the AQCC to review its leak detection and repair rules and to adopt rules to minimize emissions of certain air pollutants, (iii) clarifies that local governments have authority to regulate the siting of oil and gas locations in a reasonable manner, including the ability to inspect oil and gas facilities, impose fines for leaks, spills, and emissions, and impose fees on operators or owners to cover regulation and enforcement costs, (iv) allows local governments or oil and gas operators to request a technical review board to evaluate the effect of the local government’s preliminary or final determination on the operator’s application, (v) repeals an exemption for oil and gas production from counties’ authority to regulate noise, (vi) alters forced pooling requirements by making it more difficult to force non-consenting individuals into forced pooling agreements and (vii) elevates the protection of public health, safety, and welfare, the environment, and wildlife resources and the prevention of waste in the regulation of oil and gas development. Although industry trade associations opposed SB181, management believes that Extraction can continue to successfully operate our business. However, the enactment of SB181 and the development of related rules and regulations, which is under way, could lead to delays and additional costs to our business. For example, COGCC rulemaking on flowline safety (completed on November 21, 2019) and the Colorado AQCC and Air Pollution Control Division (“APCD”) rulemaking on air quality standards (completed December 20, 2019) – both pursuant to SB181 – could lead to such delays or costs. Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced various alternatives for ballot initiatives which would result in significantly limiting or preventing oil and natural gas development in the state. Proponents of such initiatives have begun the process of attempting to qualify six initiatives to appear on the ballot in November 2020.

Aurora and Commerce City Operator Agreements

We entered into operator agreements with the cities of Aurora and Commerce City on July 8, 2019 and September 18, 2019, respectively. The agreements established a framework for the permitting process and Extraction’s Best Management Practices while operating within the cities, including electric drilling rigs and quiet hydraulic fracturing fleets. They also identified the wells to be drilled through year-end 2025.

Rocky Mountain Midstream East Greeley Pipeline and Auburn Compressor

In October 2019, Rocky Mountain Midstream commenced service on its East Greeley Pipeline and Auburn Compressor Station and became fully operational. This pipeline and compressor station enable us to flow our oil and gas from parts of our East Greeley area without the bottlenecks or constraints we have historically experienced in this area.

Badger Central Gathering Facility

In October 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility, which enables Extraction to efficiently transport its crude oil and natural gas production along with water used during the completion process. The use of this gathering facility allows for the elimination of oil or water storage on the well pad site and reduces truck traffic, which minimizes the impact to the surrounding environment and communities.

Western Gas Outage

During portions of August and September 2019, our production on Western Gas' gathering system was significantly curtailed due to an unplanned outage at Western Gas' Lancaster gas plant. We estimate our third quarter production was negatively impacted by this outage by 8,304 BOE/d. This plant resumed normal operations in October 2019.

Involuntary Termination Charges

We expect to record involuntary termination charges of $5.6 million in the first quarter of 2020 primarily related to one-time involuntary termination benefits, office closure and relocation benefits communicated to our workforce in February 2020. This plan was initiated to align the size and composition of our workforce with our expected future operating and capital plans.

Recent Divestitures

During 2020, we completed the following divestiture:

- In February, the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $14.7 million, subject to customary purchase price adjustments.

During 2019, we completed the following divestitures:

- In December, the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $10.0 million, subject to customary purchase price adjustments.

- In August, the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $22.0 million, subject to customary purchase price adjustments.

- In March, the sale of interests in approximately 5,000 net acres of leasehold and producing properties for net sales proceeds of $16.5 million.

The Company continues to explore divestitures, as part of our ongoing initiative to divest of non-strategic assets.

Revolving Credit Facility and Capital Activity

Revolving Credit Facility Activity

During 2019, we entered into the following amendments and completed our scheduled November redetermination to our revolving credit facility:

- In November 2019, the revolving credit facility's borrowing base was decreased from $1.1 billion to $950.0 million, associated with the scheduled borrowing base redetermination. The current elected commitments were also decreased to $950.0 million.

- In August, an amendment to increase the elected commitments from $900.0 million to $1.0 billion.

- In June, an amendment to (i) increase the elected commitments from $650.0 million to $900.0 million, (ii) increase the amount for permitted letters of credit from $50.0 million to $100.0 million and increase in the letter of credit for our oil marketer from $35.0 million to $40.0 million, (iii) decrease the borrowing base from $1.2 billion to $1.1 billion and (iv) increase the limitation on permitted investments from $15.0 million to $20.0 million.

- In January, an amendment to permit prepayments and redemptions of our unsecured bonds, subject to certain term, conditions and financial thresholds.

Elevation Preferred Units

On July 10, 2019, Elevation closed on an additional 100,000 Elevation preferred units, par value $0.01 ("Elevation Preferred Units") under an existing securities purchase agreement with a third party, pursuant to which Elevation had agreed to sell an additional 100,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $100.0 million, and resulting in net proceeds of approximately $96.5 million, after deducting discounts and related offering expenses. The proceeds were used to construct the Badger central gathering facility completed in October 2019 and the Buffalo compressor station completed in the first quarter of 2020.

Senior Notes Repurchase Program

In January 2019, our Board of Directors authorized a program to repurchase up to $100.0 million of our Senior Notes ("Senior Notes Repurchase Program"). Our Senior Notes Repurchase Program does not obligate us to acquire any specific nominal amount of Senior Notes. During the year ended December 31, 2019, we have repurchased our 5.625% Senior Notes due February 1, 2026 with a nominal value of $49.8 million for $39.3 million in connection with the Senior Notes Repurchase Program.

Common Stock Repurchase Program

In November 2018, our Board of Directors authorized a program to repurchase up to $100.0 million of our common stock, which was then increased to $163.2 million in April 2019. During the two years ended December 31, 2019, we repurchased a total of 38.2 million shares of our common stock for $163.2 million and completed the stock repurchase program.

Oil, Natural Gas and NGL Data

Proved Reserves

Evaluation and Review of Proved Reserves

Our historical proved reserves estimates as of December 31, 2019, 2018 and 2017 were prepared based on reports by Ryder Scott Company, L.P. ("Ryder Scott"), our independent petroleum engineers. Within Ryder Scott, the technical person primarily responsible for preparing the estimates set forth in the Ryder Scott summary reserve reports incorporated herein for the year ended December 31, 2019 was Stephen Gardner. Mr. Gardner has been practicing consulting petroleum engineering at Ryder Scott since 2006. Mr. Gardner is a registered Professional Engineer in the State of Colorado and Texas and has over 14 years of practical experience in the estimation and evaluation of reserves. Mr. Gardner graduated from the Brigham Young University with a Bachelor of Science Degree in Mechanical Engineering. As technical principal, Mr. Gardner meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines. Ryder Scott does not own an interest in any of our properties, nor is it employed by us on a contingent basis. Ryder Scott's report is attached as Exhibit 99.1 to this Annual Report on Form 10-K.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the DJ Basin. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. These reserve estimates are reviewed and approved by our Corporate Reserves Manager. The reserves are also reviewed by our management and a committee of the Board of Directors.

Our Corporate Reserves Manager is the technical person primarily responsible for overseeing the preparation of our reserves estimates and third-party report of our reserves estimates. She holds a Bachelor of Science in mathematics with a technical minor in petroleum engineering and has over 31 years of industry experience, primarily in reservoir engineering, reserve estimation, and economic evaluation and modelling across multiple conventional and unconventional basins.

Our policies and processes regarding internal controls over the recording of reserves estimates require reserves to be in compliance with the 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. Our internal controls over reserves estimates also include the review and verification of historical production data, which are based on actual production data as reported by us; preparation of reserve estimates and verification of property ownership by our land department. Additionally, 100% of our total net proved reserves are evaluated by Ryder Scott, on an annual basis.

Estimation of Proved Reserves

Under SEC rules, proved reserves are those quantities of oil, natural gas and NGL, 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2019, 2018 and 2017 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil, natural gas and NGL and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil, natural gas and NGL reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. 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. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, historical well cost and operating expense data.

Summary of Oil, Natural Gas and NGL Reserves

The following table presents our estimated net proved oil, natural gas and NGL reserves as of December 31, 2019, 2018 and 2017.

	As of December 31,		
	2019	2018	2017
Proved Developed Producing Reserves:			
Oil (MBbls)	44,456	43,477	34,350
Natural gas (MMcf)	341,905	292,598	208,311
NGL (MBbls)	38,067	36,361	26,368
Total (MBoe)(1)	139,507	128,604	95,437
Proved Developed Non-Producing Reserves:			
Oil (MBbls)	1,351	3,598	2,728
Natural gas (MMcf)	8,403	23,901	13,925
NGL (MBbls)	934	3,328	1,564
Total (MBoe)(1)	3,685	10,910	6,613
Proved Undeveloped Reserves:			
Oil (MBbls)	45,652	88,771	74,197
Natural gas (MMcf)	229,781	386,769	403,933
NGL (MBbls)	27,008	55,162	49,174
Total (MBoe)(1)	110,957	208,395	190,693
Total Proved Reserves:			
Oil (MBbls)	91,459	135,846	111,275
Natural gas (MMcf)	580,089	703,268	626,169
NGL (MBbls)	66,009	94,851	77,106
Total (MBoe)(1)	254,149	347,908	292,743

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read "Risk Factors" appearing elsewhere in this Annual Report.

Additional information regarding our proved reserves can be found in the notes to our financial statements included elsewhere in this Annual Report.

Proved Undeveloped Reserves ("PUDs")

Annually, management develops a five-year capital expenditure plan based on our best available data at the time the plan is developed. Our capital expenditure plan incorporates a development plan for converting PUD reserves to proved developed. The development plan includes only PUD reserves that we are reasonably certain will be drilled within five years of booking based upon management's evaluation of a number of qualitative and quantitative factors, including estimated risk-based returns; estimated well density; commodity prices and cost forecasts; recent drilling recompletion or re-stimulation results and well performance; anticipated availability of services, equipment, supplies and personnel; and seasonal weather. This process is intended to ensure that PUD reserves are only booked for locations where a final investment decision has been made based on current corporate strategy. Toward the end of the third quarter and into the fourth quarter of 2019, management elected to shift corporate strategy from one of maximizing production and reserve growth to one focused on cash flow. This shift in strategy resulted in the operation of fewer future drilling rigs, resulting in fewer PUD reserves expected to be developed within five years from their date of initial booking. Reserves previously classified as PUD that are no longer expected to be drilled within five years from their date of initial booking have been reclassified to non-proved reserve categories. The company is currently only booking slightly over three years of drilling inventory as PUD. The remainder of our drilling inventory in our capital expenditure plan is currently classified in non-proved reserve categories.

Management will continue to review and revise the development plan throughout the year and may modify the development plan after evaluating a number of factors, including operating and drilling results; current and expected future commodity prices; estimated risk-based returns; estimated well density; advances in technology; cost and availability of services, equipment, supplies and personnel; acquisition and divestiture activity; and our current and projected financial condition and liquidity. If there are changes that result in certain PUD reserves no longer being scheduled for development within five years from the date of initial booking, we will reclassify those PUD reserves to non-proved reserve categories. In addition, PUD locations and reserves may be removed from the development plan ahead of their five-year life expiration as a result of changes in our development plan related to factors enumerated above.

As of December 31, 2019, our proved undeveloped reserves were composed of 45,652 MBbls of oil, 229,781 MMcf of natural gas and 27,008 MBbls of NGL, for a total of 110,957 MBoe. PUDs will be converted from undeveloped to developed as the necessary and required capital has been invested and the wells are capable of producing.

The following table summarizes our changes in PUDs during the years ended December 31, 2019, 2018 and 2017:

	MBoe
Balance, December 31, 2016	189,567
Conversion into proved developed reserves	(43,798)
Extensions and discoveries	37,573
Acquisitions	12,720
Changes in well performance, timing and other	(5,369)
Balance, December 31, 2017	190,693
Conversion into proved developed reserves	(39,498)
Extensions and discoveries	64,955
Acquisitions	12,325
Changes in well performance, timing and other	(20,080)
Balance, December 31, 2018	208,395
Conversion into proved developed reserves	(49,713)
Extensions and discoveries	26,776
Acquisitions	—
Divestitures	(2,482)
Changes in well performance, timing and other	(72,019)
Balance, December 31, 2019	110,957

Extensions and discoveries of 26,776 MBoe, 64,955 MBoe and 37,573 MBoe during the years ended December 31, 2019, 2018 and 2017, respectively, resulted primarily from new proved undeveloped locations added as a result of the drilling and completion of new wells. Downward revisions of previous estimates of 72,019 MBoe during the year ended December 31, 2019 for the line item changes in well performance, timing and other consists primarily of revisions of PUD expirations due to the SEC five year drilling rule caused by the change in business strategy to focus on cash flow rather than maximizing production and reserves growth. Of the 72,019 MBoe downward revision of previous estimates, 69,731 MBoe was due the reclassification of reserves to non-proved categories due to the aforementioned PUD expirations. The majority of the reserves are viable and can still be drilled. We intend to develop these reserves outside their five-year PUD booking window. An additional 5,483 MBoe of the downward revision of previous estimates was due to PUDs becoming uneconomic due to negative changes in SEC pricing at December 31, 2019. Downward revisions of previous estimates of 20,080 MBoe and 5,369 MBoe during the years ended December 31, 2018 and 2017, respectively, resulted primarily from the revisions resulting from price changes and revisions resulting from production and performance. In 2018, the downward revision was also due to midstream curtailment issues.

Estimated future development costs relating to the development of PUDs at December 31, 2019 were projected to be approximately $275.5 million for the year ending December 31, 2020, $193.9 million in 2021, $224.8 million in 2022, $64.0 million in 2023 and none in 2024. Costs incurred relating to the development of PUDs were $326.9 million, $392.3 million and $442.5 million during the years ended December 31, 2019, 2018 and 2017, respectively. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years. All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking. We converted 49,713 MBoe, 39,498 MBoe and 43,798 MBoe to proved developed producing reserves in the years ended December 31, 2019, 2018 and 2017, respectively. During the year ended December 31, 2019, we converted 97 PUD locations to proved developed producing reserves, which represent 24% of our PUD reserve volumes and 17% of our PUD locations as of December 31, 2019.

Productive Wells

As of December 31, 2019, we owned an average 72% working interest in 1,509 gross (1,086 net) productive wells. As of December 31, 2018, we owned an average 74% working interest in 1,538 gross (1,139 net) productive wells. As of December 31, 2017, we owned an average 71% working interest in 1,300 gross (916 net) productive wells. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2019:

	Productive Wells	
	Gross	Net
Oil wells	1,303	897
Natural gas wells	206	189
Total wells	1,509	1,086

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2019 relating to our leasehold acreage. Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and/or natural gas, regardless of whether such acreage contains proved reserves.

The following table sets forth our gross and net acres of developed and undeveloped oil and gas leases as of December 31, 2019:

	Developed Acreage(1)		Undeveloped Acreage(2)		Total Acreage	
Area	Gross	Net	Gross	Net	Gross	Net
Core DJ Basin	122,400	97,400	96,500	72,500	218,900	169,900
Other Rockies	54,500	38,700	137,300	86,800	191,800	125,500

(1) Developed acreage is acres spaced or assigned to productive wells.
(2) Undeveloped acreage are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We intend to extend our strategic leases to the extent possible and would incur approximately $103.1 million if we were to extend all of our leases set to expire in the next three years without taking into account the drilling of wells and holding leases by production. The following table sets forth the undeveloped acreage, as of December 31, 2019, that will expire in the years indicated below unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2020		2021		2022		2023 and Beyond	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Core DJ Basin	36,500	29,300	23,600	19,000	11,800	7,400	9,800	6,500
Other Rockies	40,800	18,700	24,000	14,200	24,000	13,400	13,000	7,500

Drilling Results

The following table sets forth information with respect to the number of wells completed by us during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	For the Year Ended December 31,					
	2019		2018		2017	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development Wells(1):						
Productive(2)	119.0	104.3	160.0	136.4	196.0	157.8
Dry	—	—	—	—	—	—
Exploratory Wells(1):						
Productive(2)	—	—	1.0	1.0	2.0	1.1
Dry	—	—	—	—	—	—
Total Wells(1):						
Productive(2)	119.0	104.3	161.0	137.4	198.0	158.9
Dry	—	—	—	—	—	—

(1) Includes only wells completed by us.

(2) Although a well may be classified as productive upon completion, future changes in oil, natural gas and NGL prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

As of December 31, 2019, we had 97 gross wells (78.6 net) wells waiting on commencement of completion activities.

Operations

General

We operated 96% of our horizontal production for the year ended December 31, 2019. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We sell the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to purchasers at market prices. Our largest purchaser is an oil marketer who has the ability to sell production into multiple markets.

During the year ended December 31, 2019, approximately 77% of our production was sold to one customer. However, we do not believe that the loss of any single purchaser would materially affect our business because there are numerous other potential purchasers in the area in which we sell our production. For the year ended December 31, 2019, Mercuria Energy

Trading, Inc. represented 77% of our total oil and gas revenues. For the year ended December 31, 2018, Mercuria Energy Trading, Inc. and DCP Midstream represented 76% and 11% of our total oil and gas revenues, respectively. For the year ended December 31, 2017, Mercuria Energy Trading, Inc., DCP Midstream, LP and Kerr McGee, LLC represented 65%, 19%, 11% of our total oil, gas and NGL revenues, respectively.

Revenues and operating expenses associated with the gathering systems and facilities operations will be derived from intersegment transactions for services provided to our exploration, development and production operations as well as third parties by Elevation, our unrestricted subsidiary. In October 2019, Elevation commenced moving crude oil, natural gas and water through their newly constructed Badger central gathering facility. This facility enables Extraction and will enable others to efficiently transport crude oil and natural gas production along with water used during the completion process. The use of this gathering facility allows for the elimination of oil or water storage on the well pad site and reduces truck traffic, which minimizes the impact to the surrounding environment and communities.

Transportation and Gathering

During the initial development of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is collected from the wellhead to our tank batteries and then transported by the purchaser by truck or pipeline to a tank farm, another pipeline or a refinery. Our natural gas is transported from the wellhead to the purchaser’s meter and pipeline interconnection point.

We are subject to long-term delivery commitments for the transportation and gathering of our production. Our oil marketer is subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. The aggregate remaining amount of estimated payments under these agreements is approximately $679.8 million. In May 2017, we amended our agreement with our oil marketer that requires us to sell all of our crude oil from an area of mutual interest in exchange for a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of their minimum volume commitment during the contract term. In May 2019, we extended the term of this agreement through October 31, 2020 subject to an evergreen provision thereafter where either party can provide a six month notice of termination beginning November 1, 2020. We posted a letter of credit for this agreement in the amount of $40.0 million.

We also have two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which we have a minority ownership interest. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The second agreement commenced in July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The aggregate remaining amount of estimated payments under these agreements is approximately $120.3 million.

In collaboration with several other producers and a midstream provider, on December 15, 2016 and August 7, 2017, we agreed to participate in expansions of natural gas gathering and processing capacity in the DJ Basin. The plan includes two new processing plants as well as the expansion of related gathering systems. The first plant commenced operations in August 2018 and the second plant commenced operations in July 2019. Our share of these commitments will require an incremental 51.5 and 20.6 MMcf/d, respectively, over a baseline volume of 65 MMcf/d to be delivered after the plants' in-service dates for a period of seven years thereafter. We may be required to pay a shortfall fee for any incremental volume deficiency under these commitments. These contractual obligations can be reduced by our proportionate share of the collective volumes delivered to the plants by other third-party incremental volumes available to the midstream provider at the new facilities that are in excess of the total commitments.

In November 2018, we entered into three long-term gathering agreements (the “Elevation Gathering Agreements”) for gas, crude oil and produced water with Elevation. Each agreement became effective as of July 2018 and has a term of 15 years with a dedication of certain interests in Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Elbert and Weld Counties, Colorado, and City of Broomfield Colorado within an area of mutual interest. Under the agreements, we agreed to drill 100 wells in Broomfield and 325 wells in Hawkeye by December 31, 2023 if both facilities are to be built. If Extraction fails to complete the wells by the commitment deadline, then it would be deemed to be in breach of the agreement and Elevation would be entitled to make a claim for damages against Extraction and its affiliates. The Elevation Gathering Agreements were amended in April 2019 to provide for, among other amendments, the inclusion of additional gathering facilities in Elevation’s Badger facility. Pursuant to this amendment, if these additional gathering facilities are not completed by April 1, 2020, then within 30 days of such date Extraction could be required (at Elevation's discretion) to make a payment to Elevation in the amount of 135% of all costs incurred by Elevation as of such date for the development and construction of such additional gathering facilities. Extraction does not expect to complete these additional gathering facilities by such date. As of December 31, 2019, the costs incurred by Elevation for these additional gathering facilities totaled $33.9 million. We continue to work with Elevation's financing partner in constructive discussions surrounding this target completion date. In December 2019, the Elevation Gathering Agreements were further amended such to provide Elevation additional connection fees that are consistent with market terms (the "Connect Fees"). In the fourth quarter of 2019, we incurred $19.5 million for Connect Fees pursuant to the Elevation Gathering Agreements, and we do not expect to incur more than the $23.5 million already paid during 2020 for the year ending December 31, 2020.

In February 2019, we entered into two long-term gas gathering and processing agreements with third-party midstream providers. One of the agreements additionally includes a long-term NGL sales commitment for take-in-kind NGLs from other processing agreements. The first agreement commenced in November 2019 and has a term of twenty years with a minimum volume commitment of 251 Bcf to be delivered within the first seven years. The annual commitments over seven years are to be delivered on an average of 85,000 MMcf/d in year one, 125,000 MMcf/d in year two, 140,000 MMcf/d in year three, 118,000 MMcf/d in year four, 98,000 MMcf/d in year five, 70,000 MMcf/d in year six and 52,000 MMcf/d in year seven. The aggregate remaining amount of estimated payments under this agreement is approximately $308.4 million. The second agreement commenced in January 2020 and has a term of ten years with an annual minimum volume commitment of 13.0 Bcf in years one through ten. The second agreement also includes a commitment to sell take-in-kind NGLs of 4,000 Bbl/d in year one, 7,500 Bbl/d in years two through seven with the ability to roll up to a 10% shortfall in a given month to the subsequent month. We may be required to pay an annual shortfall fee for any volume deficiencies under these commitments, calculated based on the applicable gathering and processing fees and/or, with respect to the NGL commitment, the NGL transport cost. Under our current drilling plans, we expect to meet these volume commitments.

In July 2019, we entered into three long-term contracts to supply 125,000 dekatherms of residue gas per day for five years to a transportation company. While our production is expected to satisfy these contracts, the aggregate remaining amount of estimated commitment assuming no production is $32.7 million. We posted a letter of credit for this agreement in the amount of $8.7 million.

The aggregate remaining amount of estimated payments under all of these agreements is approximately $1,141.2 million.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than we do. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil, natural gas and NGL market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained or have the ability to obtain sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil, natural gas and NGL. Demand for oil, natural gas and NGL is typically higher in the fourth and first quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Oil and Gas Leases

The typical oil and gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and gas produced from any wells drilled on the leased premises. Our interest in our properties after lessor royalties and other leasehold burdens is generally 80%. Our working interest for all producing wells averages approximately 72% and our net revenue interest is approximately 59%.

Regulation of the Oil and Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Historically, our compliance costs have not had a material adverse effect on our results of operations; however, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the administrative agencies and the courts. We cannot predict when or whether any such proposals may become effective. However, we do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Regulation Affecting Production

The production of oil and natural gas is subject to United States federal and state laws and regulations, and orders of regulatory bodies under those laws and regulations, governing a wide variety of matters. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the 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 or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the amount of oil and gas we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGL within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and gas that may be produced from our wells, negatively affect the economics of production from these wells or limit the number of locations we can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations 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.

Regulation Affecting Sales and Transportation of Commodities

Sales prices of gas, oil, condensate and NGL are not rate-regulated and instead are made at market prices. Although prices of these energy commodities are not currently rate-regulated, the United States Congress historically has been active in their regulation. We cannot predict whether new legislation to actively regulate, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state and federal reporting and compliance requirements.

The rates, terms and conditions of service of transportation of the commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of oil and natural gas produced by us, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

The Federal Energy Regulatory Commission (“FERC”) regulates interstate natural gas pipeline transportation rates and terms and conditions of service under the Natural Gas Act of 1938 (“NGA”). The FERC is continually proposing and implementing new rules and regulations affecting interstate natural gas pipeline transportation. The stated purpose of many of these regulatory changes is to ensure terms and conditions of interstate transportation service are not unduly discriminatory or unduly preferential, to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that our drilling program will be affected by any such FERC action in a manner materially differently than other similarly situated natural gas producers.

In addition to the regulation of interstate natural gas pipeline transportation, the NGA and the Natural Gas Policy Act of 1978 ("NGPA") provide FERC jurisdiction over the sale for resale of gas in interstate commerce. In addition, the Energy Policy Act of 2005 ("EPAct 2005") made it unlawful for "any entity," including producers such as us, that are otherwise not subject to FERC's jurisdiction under the NGA to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. FERC’s rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to FERC's jurisdiction or the purchase or sale of transportation services subject to FERC's jurisdiction, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives FERC authority to impose civil penalties up to approximately $1.2 million per day per violation for violations of the NGA and the NGPA. The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under FERC Order No. 704 (defined below).

In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order No. 704"). Under Order No. 704, certain market participants, including producers engaging in certain wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. Not all types of natural gas sales are required to be reported on Form No. 552. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 is intended to increase the transparency of wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and terms and conditions of service of interstate transportation of liquids, including oil and NGL, under the Interstate Commerce Act, as it existed on October 1, 1977 ("ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. The ICA requires that certain interstate liquids pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

The rates charged by many interstate liquids pipelines are currently adjusted pursuant to an annual indexing methodology established and regulated by FERC, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. This adjustment is subject to review every five years. Under FERC’s regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by obtaining market-based rate authority (demonstrating the pipeline lacks market power), by establishing rates by settlement with all existing shippers, or through a cost-of-service approach (if the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology). Increases in liquids transportation rates may result in lower revenue and cash flows for us.

In addition, due to common carrier regulatory obligations for interstate liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity or to accommodate requests for service from new shippers. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to liquids pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Rates for intrastate pipeline transportation of liquids are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly situated competitors.

In addition to FERC’s regulations, we are required to observe anti-market manipulation laws with regard to our physical sales of energy commodities. In November 2009, the Federal Trade Commission ("FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007, intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately $1.1 million per violation per day. In July 2010, Congress passed the Dodd-Frank Act, which expanded the authority of the Commodity Futures Trading Commission ("CFTC") to prohibit market manipulation in the markets it regulates. This authority, with respect to oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to oil purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of approximately $1.1 million or triple the monetary gain to the person for each violation.

Some of our pipeline assets and third-party pipelines on which we rely are subject to safety regulation by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (“PHMSA”). In recent years, PHMSA has been active in proposing and finalizing additional regulations for natural gas and hazardous liquids pipelines. In April 2016, PHMSA proposed a rule regarding the safety of natural gas transmission pipelines and gas gathering pipelines in April 2016. In October 2019, PHMSA issued a final rule on the natural gas transmission lines portion of the April 2016 rulemaking, and PHMSA is expected to finalize the rules with respect to gathering lines in 2020. With respect to transmission pipelines, the final rule changes integrity management requirements, expands assessment and repair requirements for pipelines in “moderate-consequence areas,” including areas of medium population density, and increases requirements for monitoring and inspection of pipeline segments not located in “high-consequence areas.” The final rule also requires that records or other data relied on to determine operating pressures must be traceable, verifiable and complete. If the pending gathering-pipeline portion of the rulemaking ultimately includes a final rule that applies similar requirements to gathering lines, some gathering pipeline operators, including us, may be forced to reduce their allowable operating pressures, which would reduce the amount of capacity available to us. As PHMSA has yet to finalize this rulemaking as applied to gathering lines, however, the contents and timing of any final rule are uncertain. Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

Effective April 2017, PHMSA adopted new rules increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations to up to $218,649 per violation per day and up to approximately $2.2 million for a related series of violations.

Regulation of Environmental and Safety and Health Matters

Our operations are subject to numerous stringent and complex federal, state and local laws and regulations governing safety and health aspects of our operations, the release, disposal, or discharge of materials into the environment or otherwise relating to environmental protection. Governmental entities, including the U.S. Environmental Protection Agency ("EPA"), the U.S. Occupational Safety and Health Administration ("OSHA") and analogous state agencies, including the COGCC, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) impose limitations on the time, place and manner on drilling and other regulated activities; (iii) restrict the types, quantities and concentration of various materials that may be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iv) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (v) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (vi) apply specific health and safety criteria addressing worker protection; and (vii) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, including the assessment of monetary fines or penalties, the imposition of investigatory, remedial or corrective obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations in a particular area.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities, or waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental spills or releases may occur in the course of our operations that can result in the occurrence of significant costs and liabilities, including any third-party claims for damage to property, natural resources or persons. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

On April 16, 2019, SB181 became law, increasing the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development. Among other things, SB181 (i) repeals a prior law restricting local government land use authority over oil and gas mineral extraction areas to areas designated by the COGCC, (ii) directs the AQCC to review its leak detection and repair rules and to adopt rules to minimize emissions of certain air pollutants, (iii) clarifies that local governments have authority to regulate the siting of oil and gas locations, including the ability to inspect oil and gas facilities, impose fines for leaks, spills, and emissions, and impose fees on operators or owners to cover regulation and enforcement costs, (iv) allows local governments or oil and gas operators to request a technical review board to evaluate the effect of the local government’s preliminary or final determination on the operator's application, (v) repeals an exemption for oil and gas production from counties’ authority to regulate noise, (vi) alters forced pooling requirements by making it more difficult to force non-consenting individuals into forced pooling agreements and (vii) elevates the protection of public health, safety, and welfare, the environment, and wildlife resources and the prevention of waste in the regulation of oil and gas development. The enactment of SB181 and the development of related rules and regulations, which is under way, could lead to delays and additional costs to our business. For example, COGCC rulemaking on flowline safety (completed on November 21, 2019) and the Colorado AQCC and APCD rulemaking on air quality standards (completed December 20, 2019) – both pursuant to SB181 – could lead to such delays or costs.

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

Hazardous Substances and Wastes

The Resource Conservation and Recovery Act ("RCRA"), and analogous state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the guidance issued by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. For example, in December 2016, several environmental groups and the EPA entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. In April 2019, the EPA determined in a document entitled "Management of Oil and Gas Exploration, Development and Production Wastes: Factors Informing a Decision on the Need for Regulatory Action" that revisions to these oil and gas waste regulations were not necessary because the main causes for uncontrolled releases of oil and gas waste are appropriately and more readily addressed within the framework of existing state regulatory programs. In the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes. We are required to manage the disposal of hazardous and non-hazardous wastes in compliance with RCRA and analogous state laws. RCRA currently exempts many exploration and production wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other wastes intrinsically associated with the exploration, development, or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state solid waste laws and regulations, and it is possible that certain oil and natural gas exploration and production wastes currently classified as non-hazardous could be classified as hazardous waste in the future. Stricter regulation of wastes generated during our or our customer's operations could result in an increase in our and our customers', as well as the oil and natural gas exploration and production industry's, costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the transport or disposal of a hazardous substance released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA and any state analogs may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, 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 generate materials in the course of our operations that may be regulated as hazardous substances.

We currently own, lease, or operate, and in the past have owned, leased or operated, numerous properties that have been used for oil and natural gas exploration, production and processing and other operations for many years. Hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned, leased or operated by us, or on, under or from other locations where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of substances, including hazardous substances, wastes, or petroleum hydrocarbons, was not under our control. These properties and the hazardous substances, wastes or petroleum hydrocarbons disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination, the costs of which could have a material adverse effect on our business and results of operations.

Water Discharges

The Federal Water Pollution Control Act, also known as the Clean Water Act ("CWA"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other hazardous substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters, including jurisdictional wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In June 2015, the EPA and the U.S. Army Corps of Engineers ("Corps") published a final rule to revise the definition of "waters of the United States" ("WOTUS") for all CWA programs, but legal challenges to this rule followed and the rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015. In January 2018, the U.S. Supreme Court ruled that the rule revising the WOTUS definition must first be reviewed in the federal district courts, which resulted in a withdrawal of the stay by the Sixth Circuit. Subsequent litigation in the federal district courts resulted in patchwork application of the rule in some states (e.g., California, Oklahoma), but not others (e.g. Colorado). In July 2017, the EPA proposed to repeal the 2015 rule revising the WOTUS definition and, in December 2018, EPA and the Corps issued a proposed rule revising the WOTUS definition that would provide discrete categories of jurisdictional waters and tests for determining whether a particular water body meets any of those classifications. In October 2019, the EPA issued a final rule repealing the 2015 rule (which became effective in December 2019 and has already been challenged in federal district courts in New Mexico, New York, and South Carolina). In January 2020, the EPA announced a final rule redefining the WOTUS definition. Several groups have already announced their intentions to challenge the final revision rule. To the extent the repeal and revision rules are successfully challenged and the 2015 rule is enforced in jurisdictions in which we operate or a replacement rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas in connection with any expansion activities. Federal and state regulatory agencies may impose substantial administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations, including spills and other non-authorized discharges.

The Oil Pollution Act of 1990 ("OPA"), amends the CWA and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Subsurface Injections

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the Safe Drinking Water Act ("SDWA") and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of produced water and ultimately increase the cost of our operations. For example, in response to recent seismic events near belowground disposal wells used for the injection of oil and natural gas-related wastewaters, regulators in some states, including Colorado, have imposed more stringent permitting and operating requirements for produced water disposal wells. In Colorado, permit applications are reviewed specifically to evaluate seismic activity and, as of 2011, the state has required operators to identify potential faults near proposed wells, if earthquakes historically occurred in the area, and to accept maximum injection pressures and volumes based on fracture gradient as conditions to permit approval. Additionally, legal disputes may arise based on allegations that disposal well operations have caused damage to neighboring properties or otherwise violated state or federal rules regulating waste disposal. These developments could result in additional regulation, restriction on the use of injection wells by us or by commercial disposal well vendors whom we may use from time to time to dispose of wastewater, and increased costs of compliance, which could have a material adverse effect on our capital expenditures and operating costs, financial condition, and results of operations.

Air Emissions

The Clean Air Act (the "CAA") and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance standards. 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 strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be charged royalties on natural gas losses or required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in 2016, EPA designated the Denver Metro North Front Range as Marginal non-attainment for the 2008 National Ambient Air Quality Standard ("NAAQS") for ozone. In August 2019, the EPA proposed to reclassify the Denver Metro North Front Range area as a serious non-attainment area for ozone due to high levels detected in 2016 and 2017. The proposal would set a new deadline of July 20, 2021 for the Denver area to attain the 2008 ozone standard. Reclassification of areas or imposition of more stringent standards (including a lowering of the major source threshold for volatile organic compounds and oxides of nitrogen and the resulting increased likelihood that a source may be subject to Non-Attainment New Source Review) may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent requirements as a result of this new final rule, which could apply to our operations. In addition, during the fall of 2016, EPA issued final Control Techniques Guidelines ("CTGs") for reducing volatile organic compound emissions from existing oil and natural gas equipment and processes in ozone non-attainment areas, including the Denver Metro North Front Range Ozone 8-hour Non-Attainment area. In 2017, as part of the federal CTG process for oil and natural gas, Colorado undertook a stakeholder and rulemaking effort to compare the CTGs to existing Colorado requirements to ensure they meet applicable federal requirements, which resulted in revisions to Colorado's Regulation Number 7. The new state regulations include more stringent air quality control requirements applicable to our operations. In another example, in June 2016, the EPA finalized a revised rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent permitting requirements. Compliance with these or other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could have a material adverse impact on our business and results of operations.

Regulation of Greenhouse Gas ("GHG") Emissions

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has adopted rules under authority of the CAA that, among other things, establish Potential for Significant Deterioration ("PSD") construction and Title V operations permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting "best available control technology" standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published the New Source Performance Standards ("NSPS") Subpart OOOOa standards that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. However, in September 2019, under the new administration, EPA proposed to remove transmission and storage activities from the purview of the OOOOa standards, thereby rescinding the VOC and methane emissions limits applicable to those activities. The proposed rule would also rescind the methane limit emissions for production and processing sources, but would maintain emissions limits for VOCs. In the alternative, the EPA also proposed to simply rescind the methane requirements for all oil and natural gas sources, without removing any activities from the source category. Similarly, in September 2018, the federal Bureau of Land Management ("BLM") issued a rule that relaxes or rescinds certain requirements of its November 2016 rule enacted to reduce methane emissions by regulating venting, flaring, and leaks from oil and gas operations on federal and American Indian lands. California and New Mexico have challenged the rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit aiming to force EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas section; that lawsuit is currently pending (as of October

2019, the EPA had requested a stay of the litigation pending the outcome of its proposed overhaul of the 2016 methane requirements).

On the international level, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In follow-up to an earlier announcement by President Trump, in August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement and on November 4, 2019, the U.S. submitted formal notification of its withdrawal to the United Nations. The withdrawal will take effect one year from delivery of the notification, although there is a possibility that a new administration could choose to rejoin the Paris Agreement.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHG or otherwise limit emissions of GHG from our equipment and operations could result in increased costs to reduce emissions of GHG associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant. One or more of these developments could have a materially adverse effect on our business, financial condition and results of operations. Additionally, it should be noted that increasing concentrations of GHG in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations. Finally, notwithstanding potential risks related to climate change, the International Energy Agency, an autonomous intergovernmental organization involved in international energy policy, estimates that global energy demand will continue to rise and will not peak until after 2040 and oil and gas will continue to represent a substantial percentage of global energy use over that time. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemical additives under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions or similar state agencies. However, several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, in June 2016 the EPA published final effluent limitations guidelines pursuant to its authority under the SDWA prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; asserted regulatory authority in 2014 under the SDWA over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 establishing new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including well casing and wastewater storage requirements and an obligation for exploration and production operators to disclose what chemicals they are using in fracturing activities. Following years of litigation, the BLM rescinded the rule in December 2017; however, that rescission has been challenged by several environmental groups and states in ongoing litigation (oral arguments were heard in the case in January 2020 after a long hiatus). Also, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

At the state level, Colorado, where we conduct operations, is among the states that has adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. For example, significant new oil and gas-related rules and regulations are currently being developed in Colorado following the enactment of SB181 in April 2019, which increased local control and elevated public health, safety and environmental concerns in the regulation of oil and gas development in the state. This legislation also explicitly authorizes cities and counties in the state to develop and implement local-level oil and gas regulations. The COGCC must approve the bulk of the new rules and regulations developed under Senate Bill 19-181, by July 1, 2020. Moreover, other states could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Also, certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives (including proposed ballot initiatives for 2020) that, if approved, would allow revisions to the state constitution in a manner that would make such exploration and production activities in the state more difficult in the future. In addition to state laws, local land use restrictions may restrict drilling or the hydraulic fracturing process and cities may adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions but regulating the time, place and manner of those activities. For example, in January 2020, Broomfield, Colorado passed an ordinance prohibiting overnight oil and gas operations. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

In the event that local or state restrictions or prohibitions are adopted in areas where we conduct operations, including the DJ Basin in Colorado, that impose more stringent limitations on the production and development of oil and natural gas, including, among other things, the development of increased setback distances, we and similarly situated oil and natural exploration and production operators in the state may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we and similarly situated operates are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Moreover, because most of our operations are conducted in a particular area, the DJ Basin in Colorado, legal restrictions imposed in that area will have a significantly greater adverse effect than if we had our operations spread out amongst several diverse geographic areas. Consequently, in the event that local or state restrictions or prohibitions are adopted in the DJ Basin in Colorado that impose more stringent limitations on the production and development of oil and natural gas, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Activities on Federal Lands

Oil and natural gas exploration, development and production activities on federal lands, including American Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. While we currently have minimal exploration, development and production activities on federal lands, our proposed exploration, development and production activities are expected to include leasing of federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the requirements of NEPA. This process has the potential to delay or limit, or increase the cost of, the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in Environmental Assessments or Environmental Impact Statements, we could incur added costs, which may be substantial. In January 2020, the White House Council on Environmental Quality ("CEQ") proposed changes to NEPA regulations designed to overhaul the system and speed up federal agencies' approval of projects. Among other things, the rule proposes to narrow the definition of "effects" to exclude the terms "direct," "indirect," and "cumulative" and redefine the term to be "reasonably foreseeable" and having "a reasonably close causal relationship to the proposed action or alternatives." Changes to the NEPA regulations could have an effect on our operations and our ability to obtain governmental permits. We continuously evaluate the effect of new rules on our business.

Endangered Species and Migratory Birds Considerations

The federal Endangered Species Act ("ESA"), and comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or that species' habitat. Similar protections are offered to migrating birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. Moreover, as a result of one or more agreements entered into by the U.S. Fish and Wildlife Service, the agency is required to make a determination on listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The identification or designation of previously unprotected species as threatened or endangered in areas where our operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Employee Safety and Health

We are subject to the requirements of the Occupational Safety and Health Act and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right-To-Know Act and comparable state statutes and any implementing regulations require that we maintain and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. For example, under a new OSHA standard limiting respirable silica exposure, the oil and gas industry must implement engineering controls and work practices to limit exposures below the new limits by June 2021. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations. Further, we have no coverage for gradual, long-term pollution events.

Employees

As of December 31, 2019, we employed 323 people. As of March 12, 2020, we employed 256 people. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

From time to time we utilize the services of independent contractors to perform various field and other services.

Facilities

Our corporate headquarters is located in Denver, Colorado. Our Central Gathering Facility is located in Weld County, Colorado.

Available Information

Our common stock is listed and traded on the NASDAQ under the symbol "XOG." Our reports, proxy statements and other information filed with the SEC can be inspected and copied at the offices of the NASDAQ, at One Liberty Plaza, 165 Broadway, New York, New York 10006.

We also make available free of charge through our website, www.extractionog.com, electronic copies of certain documents that we file with the SEC, including our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 1A. RISK FACTORS

RISK FACTORS

There are many factors that may affect our business and results of operations. If any of the following risks actually occur, our business, financial condition and results of operations could be materially and adversely affected and we may not be able to achieve our goals. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business.

Risks Related to the Oil, Natural Gas and NGL Industry and Our Business

Oil and natural gas prices are volatile. An extended or further decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil, natural gas and NGL production heavily influence our revenue, profitability, access to capital and future rate of growth. The commodities market has historically been and will likely continue to be volatile. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGL;
- the price and quantity of foreign imports;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indices in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the extent to which members of OPEC and other oil exporting nations agree to and maintain oil price and production controls;
- weather conditions;
- technological advances affecting energy consumption;
- the effect of worldwide energy conservation and environmental protection efforts;
- the price and availability of alternative fuels;
- domestic, local and foreign governmental regulation and taxes;
- shareholder activism and activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas; and
- global or national health epidemics or concerns, such as the recent coronavirus outbreaks, which may reduce demand for oil, natural gas and related products because of reduced global or national economic activity.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil, natural gas and NGL that we can produce economically and may impact our ability to satisfy our obligations under firm-commitment transportation agreements. We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements may be limited, and we are not under an obligation to hedge a specific portion of our oil or natural gas production.

Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits. While it is difficult to project future economic conditions and whether such conditions will result in impairment of proved property costs, we consider several variables including 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. In addition, sustained periods with oil and natural gas prices at levels lower than current West Texas Intermediate strip prices and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves and related standardized measure. If we are required to curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential liabilities, including environmental liabilities. Such assessments are inexact and inherently uncertain. For these reasons, the properties we have acquired or will acquire in the future may not produce as projected. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as pipe corrosion or groundwater contamination, when a review is performed. We may be unable to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

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

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development and acquisition of oil and natural gas reserves. In 2020, we plan to invest $485 million to $555 million in our operations, including $425 million to $475 million for drilling and completion of operated and non-operated wells, including $20 million to $30 million for leasehold and other, and up to $50 million for midstream infrastructure development, a portion of which will be funded by Extraction. We expect to fund our 2020 capital expenditures with borrowings under our revolving credit facility, cash flows from operations and possibly through asset sales or additional capital markets transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. See "Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Substantially all of our producing properties are located in the DJ Basin of Colorado, making us vulnerable to risks associated with operating in one major geographic area. Specifically, as the DJ Basin is an area of high industry activity, we may be unable to hire, train or retain qualified personnel needed to manage and operate our assets.

Substantially all of our producing properties are geographically concentrated in the DJ Basin of Colorado, an area in which industry activity has increased rapidly. At December 31, 2019, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors or other regional events, delays or interruptions of production from wells in this area caused by governmental regulation, including at the state and local level, processing or transportation capacity constraints, market limitations, water shortages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGL. For example, bottlenecks in processing and transportation that have occurred in some recent periods in the Wattenberg Field have negatively affected our results of operations. Similarly, the concentration of our producing assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules that 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, the demand for, and cost of, drilling rigs, equipment, supplies, personnel, and oilfield services increase. Shortages or the high cost of drilling rigs, equipment, supplies, personnel, or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital forecast, which could have a material adverse effect on our business, financial condition, or results of operations.

Specifically, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years and may increase substantially in the future. Moreover, our competitors, including those operating in multiple basins, may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could have a negative effect on production volumes or significantly increase costs, which could have a material adverse effect on our results of operations, liquidity and financial condition.

Changes in the legal and regulatory environment governing the oil and natural gas industry, particularly changes specific to the DJ Basin of Colorado, could have a material adverse effect on our business

Our business is subject to various forms of government regulation. Some local governments are adopting new requirements and restrictions on hydraulic fracturing and other oil and natural gas operations. Some local governments 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. Beyond that, during the past few years, a total of five Colorado cities have passed voter initiatives temporarily or permanently prohibiting hydraulic fracturing. Since that time, local district courts have struck down the ordinances for certain of those Colorado cities, and such decisions were upheld by the Colorado Supreme Court in May 2016. Nevertheless, there is a continued risk that cities will adopt local ordinances that seek to regulate the time, place, and manner of hydraulic fracturing activities and oil and natural gas operations within their respective jurisdictions.

In addition, in 2014, 2016 and 2018, opponents of hydraulic fracturing sought statewide ballot initiatives that would have restricted oil and gas development in Colorado. The 2014 initiatives were withdrawn in return for the creation of a task force to craft recommendations for minimizing land use conflicts over the location of oil and natural gas facilities, and none of the 2016 initiatives were successful. However, in 2018, the Colorado Secretary of State approved a citizen-initiated ballot measure, referred to as Prop. 112, for inclusion on the statewide voter ballot in November 2018. Although Prop. 112 was ultimately unsuccessful, similar efforts are likely to continue in the future, which, if successful, could result in dramatically reducing the area available for future oil and gas development in Colorado or outright banning oil and gas development in Colorado. We cannot predict the nature or outcome of future ballot initiatives or other similar efforts. If we are required to cease operating in any of the areas in which we now operate as the result of bans or moratoria on drilling or related oilfield services activities, it could have a material effect on our business, financial condition, and results of operations.

Additionally, we are subject to laws and regulations concerning the location, spacing and permitting of the oil and natural gas wells we drill, among other matters. In particular, our business utilizes a methodology available in Colorado known as "forced pooling," which refers to the ability of a holder of an oil and natural gas interest in a particular prospective drilling spacing unit to apply to the COGCC for an order forcing all other holders of oil and natural gas interests in such area into a common pool for purposes of developing that drilling spacing unit. This methodology is especially important for our operations in the Greeley area, where there are many interest holders. Changes in the legal and regulatory environment governing our industry, particularly any changes to Colorado forced pooling procedures that make forced pooling more difficult to accomplish, could result in increased compliance costs and adversely affect our business, financial condition and results of operations. SB181, enacted in April 2019, changed forced pooling requirements in the state of Colorado by requiring the consent of 45% of mineral interest holders, thus making it more difficult to force non-consenting individuals into forced pooling agreements.

The enactment of Senate Bill 19-181 "Protect Public Welfare Oil and Gas Operations" increased the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development, which could have a material adverse effect on our business.

On April 16, 2019, SB181 became law, increasing the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development. Among other things, SB181 (i) repeals a prior law restricting local government land use authority over oil and gas mineral extraction areas to areas designated by the COGCC, (ii) directs the AQCC to review its leak detection and repair rules and to adopt rules to minimize emissions of certain air pollutants, (iii) clarifies that local governments have authority to regulate the siting of oil and gas locations, including the ability to inspect oil and gas facilities, impose fines for leaks, spills, and emissions, and impose fees on operators or owners to cover regulation and enforcement costs, (iv) allows local governments or oil and gas operators to request a technical review board to evaluate the effect of the local government's preliminary or final determination on the operator's application, (v) repeals an exemption for oil and gas production from counties' authority to regulate noise, (vi) alters forced pooling requirements by making it more difficult to force non-consenting individuals into forced pooling agreements and (vii) elevates the protection of public health, safety, and welfare, the environment, and wildlife resources and the prevention of waste in the regulation of oil and gas development. The enactment of SB181 and the development of related rules and regulations, which is under way, could lead to delays and additional costs to our business. For example, COGCC rulemaking on flowline safety (completed on November 21, 2019) and the Colorado AQCC and APCD rulemaking on air quality standards (completed December 20, 2019) – both pursuant to SB181 – could lead to such delays or costs.

Similar efforts to SB181 are likely to continue in the future, which, if successful, could result in dramatically reducing the area available for future oil and gas development in Colorado or outright banning oil and gas development in Colorado. We cannot predict the nature or outcome of future ballot initiatives, legislative actions or other similar efforts, or the effects of implementation of SB181 by local governments in Colorado. The enactment of SB181 may lead to delays and additional costs to our operations. Furthermore, if we are required to cease operating in any of the areas in which we now operate as the result of bans or moratoria on drilling or related oilfield services activities, it could have a material effect on our business, financial condition, and results of operations.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- the availability of takeaway capacity;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our revolving credit facility.

If our revenues or the borrowing base under our revolving credit facility decreases as a result of lower oil, natural gas and NGL 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 and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our revolving credit facility are 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 properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition and results of operations.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and a failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our business, financial condition, results of operations or cash flows.

Our future growth prospects are dependent upon our ability to identify optimal strategies for investing our capital resources to produce rates of return. In developing our business plan, we consider allocating capital and other resources to various aspects of our business including well development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also consider our likely sources of capital, including cash generated from operations and borrowings under our credit agreement. Notwithstanding the determinations made in the development of our business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and future growth may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

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, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to purchase, explore, develop or otherwise exploit prospects 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 "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with environmental and other regulatory requirements including limitations on or resulting from wastewater discharge and disposal, subsurface injections, GHG emissions and hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- lack of available capacity on interconnecting transmission pipelines;
- equipment failures or accidents, such as fires or blowouts;
- lack of available gathering facilities or delays in construction of gathering facilities;
- adverse weather conditions, such as blizzards, tornados and ice storms;
- issues related to compliance with environmental and other governmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil, natural gas and NGL prices;
- limited availability of financing at acceptable terms;
- title problems or legal disputes regarding leasehold rights; and
- limitations in the market for oil, natural gas and NGL.

Our identified drilling locations are scheduled over many 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 such locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained or if existing producing wells that are holding leases with other potential locations cease to continue to produce in commercial quantities, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

A substantial portion of our reserves are located in urban areas, which could increase our costs of development and delay production.

A substantial portion of our reserves are located in urban portions of the DJ Basin, which could disproportionately expose us to operational and regulatory risk in that area. Much of our operations are within the city limits of various municipalities in northeastern Colorado. In such urban and other populated areas, we may incur additional expenses, including expenses relating to mitigation of noise, odor and light that may be emitted in our operations, expenses related to the appearance of our facilities and limitations regarding when and how we can operate. The process of obtaining permits for drilling or for gathering lines to move our production to market in such areas may be more time consuming and costly than in more rural areas. In addition, we may experience a higher rate of litigation or increased insurance and other costs related to our operations or facilities in such highly populated areas.

Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and gas production, and our initiatives to expand our access to midstream and operational infrastructure may be unsuccessful.

The marketing of oil and natural gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. The availability of these facilities also could be impacted by the comprehensive regulatory structure under which these facilities operate, as detailed in "Business — Regulation Affecting Sales and Transportation of Commodities." If there is insufficient capacity available on these systems, or if these facilities are unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise, especially in areas of planned expansion where such facilities do not currently exist. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. For example, recent increases in activity in the DJ Basin have contributed to bottlenecks in processing and transportation that have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Additionally, we continued to experience constraints on the capacity available in certain pipelines that we use to transport natural gas and have been forced to shut in some production from time to time. Capacity constraints typically reduce the productivity of some of our older vertical wells and may on occasion limit incremental production from some of our newer horizontal wells. This constrains our production and reduces our revenue from the affected wells. Capacity constraints affecting natural gas production also impact the associated NGL. We are also dependent on the availability and capacity of oil purchasers for our production. Increases in the amount of oil that we transport out of the DJ Basin for sale would result in an increase in our transportation costs and would reduce the price we receive for the affected production.

Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the DJ Basin, we are subject to increasing competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages or delays. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

While we have undertaken initiatives to expand our access to midstream and operational infrastructure, these initiatives may be delayed or unsuccessful. As a result, our business, financial condition and results of operations could be adversely affected.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our debt arrangements contain a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make certain acquisitions and investments;
- enter into mergers, consolidations or other transactions resulting in the transfer of all or substantially all of our assets;
- make certain payments, including paying dividends or distributions in respect of our equity;
- hedge future production or interest rates;
- redeem and prepay other debt;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, our debt arrangements require us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our debt arrangements will impose on us.

Our revolving credit facility limits the amount we can borrow up to the lower of our aggregate lender commitments and a borrowing base amount, which the lenders, in their sole discretion, will determine on a semi-annual basis based upon projected revenues from the oil and natural gas properties securing our loan. The lenders will be able to unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders does not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. We will be required to repay outstanding borrowings in excess of the borrowing base. Our borrowing base is $950.0 million, subject to the current maximum lending commitments of $950.0 million.

A breach of any covenant in our revolving credit facility will result in a default under the revolving credit facility after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us. In addition, our obligations under our revolving credit facility are secured by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 90% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets.

The borrowing base under our revolving credit facility may be reduced in light of recent declines in commodity prices, which could hinder or prevent us from meeting our future capital needs.

The borrowing base under our revolving credit facility is currently $950.0 million, and lender commitments under the revolving credit facility are $950.0 million. Our borrowing base is redetermined semiannually on each May 1 and November 1 based on certain factors, including our reserves and hedge position, with the next borrowing base redetermination scheduled to occur in May 2020. Our borrowing base may decrease as a result of the recent decline in natural gas, NGLs, and oil prices, or as a result of operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or other reasons. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which could have a material adverse effect on our financial condition and results of operations and our ability to service our indebtedness.

We may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations.

Declines in commodity prices may cause the financial markets to exert downward pressure on stock prices and credit capacity for companies throughout the energy industry. For example, for portions of 2019, the market for senior unsecured notes was unfavorable for high-yield issuers such as us. Our plans for growth may require access to the capital and credit markets, including the ability to issue senior unsecured notes. Although the market for high-yield debt securities experienced periods of improvement in 2019, if the high-yield market deteriorates, or if we are unable to access alternative means of debt or equity financing on acceptable terms, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which could have a material adverse effect on our financial condition and results of operations and our ability to service our indebtedness.

We may be subject to risks in connection with divestitures

In 2019, we announced our ongoing initiative to divest of non-strategic assets in order to increase capital resources available for other core assets, create organizational and operational efficiencies or for other purposes and completed divestitures of several of our non-strategic assets and we have additional divestitures pending, as discussed in "Business—Recent Developments." Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties and the availability of purchases willing to acquire the assets with terms we deem acceptable. Though we continue to evaluate various options for the divestiture of such assets, there can be no assurance that this evaluation will result in any specific further action.

Sellers often retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our debt arrangements, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our Senior Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. If oil and natural gas prices remain at their current level for an extended period of time or decline, we may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt arrangements may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our revolving credit facility and the indentures governing our 2024 Notes and 2026 Notes currently restrict our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, natural gas and NGL, we enter into commodity derivative contracts for a significant portion of our production, primarily consisting of swaps, put options and call options. See "Management's Discussion and Analysis of Financial Condition and Results of

Operations—Overview—Sources of Our Revenues." Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments 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 contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil, natural gas and NGL prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil, natural gas and NGL, which could also have an adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the contract and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. While we utilize multiple counterparties, if the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare reserve estimates, we must project production rates and 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, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil, natural gas and NGL 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 our reserves. In addition, we may revise reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, our estimated proved reserves as of December 31, 2019 were calculated under SEC rules using the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months of $55.69/Bbl for oil and $2.58/MMBtu for natural gas, which for certain periods of 2019 were substantially above the available spot oil and natural gas prices. Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits.

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

Reserve engineers rely in part on the production history of nearby wells in establishing reserve estimates for a particular well or field. Horizontal drilling in the DJ Basin is a relatively recent development, whereas vertical drilling has been utilized by producers in this area for over 50 years. As a result, the amount of production data from horizontal wells available to reserve engineers is relatively small compared to that of production data from vertical wells. Until a greater number of horizontal wells have been completed in the DJ Basin, and a longer production history from these wells has been established, there may be a greater variance in our proved reserves on a year-over-year basis due to the transition from vertical to horizontal reserves in both the proved developed and proved undeveloped categories. We cannot assure you that any such variance would not be material and any such variance could have a material and adverse impact on our cash flows and results of operations. If our horizontal wells do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects.

Part of our strategy involves drilling using the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. During the year ended December 31, 2019, we drilled 107 gross operated horizontal wells and completed 119 gross operated horizontal wells and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage. In addition, our horizontal drilling activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. 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 and/or commodity prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Approximately 54% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

As of December 31, 2019, approximately 54% of our net leasehold acreage was undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. Unless production is established on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

We are required to pay fees to our service providers based on minimum volumes under long-term contracts regardless of actual volume throughput.

We may enter into firm transportation, gas processing, gathering and compression service, water handling and treatment, or other agreements that require minimum volume delivery commitments.

Our oil marketer is subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. The aggregate remaining amount of estimated payments under these agreements is approximately $679.8 million. In May 2017, we amended the agreement with our oil marketer that requires them to sell all of their crude oil from an area of mutual interest in exchange for a make-whole provision that allows us to satisfy any minimum volume commitment deficiencies incurred by our oil marketer with future barrels of crude oil in excess of the minimum volume commitment during the contract term. In May 2019, we extended the term of this agreement through October 31, 2020 subject to an evergreen provision thereafter where either party can provide a six month notice of termination beginning November 1, 2020. Due to the contract termination date, the amount of consideration recognized in revenue is reduced. We have posted a letter of credit for this agreement in the amount of $40.0 million.

We also have two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which we have a minority ownership interest. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The second agreement commenced in July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The aggregate remaining amount of estimated payments under these agreements is approximately $120.3 million.

In February 2019, we entered into two long-term gas gathering and processing agreements with third-party midstream providers. One of the agreements additionally includes a long-term NGL sales commitment for take-in-kind NGLs from other processing agreements. The first agreement commenced in November 2019 and has a term of twenty years with a minimum volume commitment of 251 Bcf to be delivered within the first seven years. The annual commitments over seven years are to be delivered on an average 85,000 Mcf/d in year one, 125,000 Mcf/d in year two, 140,000 Mcf/d in year three, 118,000 Mcf/d in year four, 98,000 Mcf/d in year five, 70,000 Mcf/d in year six and 52,000 Mcf/d in year seven. The aggregate remaining amount of estimated payments under this agreement is approximately $308.4 million. The second agreement commenced on January 2020 and has a term of ten years with an annual minimum volume commitment of 13.0 Bcf in years one through ten. The second agreement also includes a commitment to sell take-in-kind NGLs of 4,000 Bbl/d in year one, 7,500 Bbl/d in years two through seven with the ability to roll up to a 10% shortfall in a given month to the subsequent month. We may be required to pay a shortfall fee for any volume deficiencies under these commitments, calculated based on the applicable gathering and processing fees and/or, with respect to the NGL commitment, the NGL transport cost.

In July 2019, the Company entered into three long-term contracts to supply 125,000 dekatherms of residue gas per day for five years to a transportation company. While our production is expected to satisfy these contracts, the aggregate remaining amount of estimated commitment assuming no production is $32.7 million. We posted a letter of credit for this agreement in the amount of $8.7 million.

The aggregate remaining amount of estimated payments under all of these agreements is approximately $1,141.2 million.

If we have insufficient production to meet the minimum volumes under these agreements or any other firm commitment agreement we may enter into, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results or operations.

If we are unable to meet our commitments under the Elevation Gathering Agreements or Elevation’s limited liability company agreement, we may incur additional costs or, in certain cases, may lose control of Elevation.

If we are unable to meet our commitments under the Elevation Gathering Agreements, we may be required to incur additional costs. For example, if we fail to complete wells by the commitment deadline, we would be deemed to be in breach of the agreements and Elevation would be entitled to make a claim for damages against us and our affiliates. Additionally, if certain additional gathering facilities are not completed by April 1, 2020, then within 30 days of such date we could (at Elevation's discretion) be required to make a payment to Elevation in the amount of 135% of all costs incurred by Elevation as of such date for the development and construction of such additional gathering facilities. We do not expect to complete these additional gathering facilities by such date. As of December 31, 2019, the costs incurred by Elevation for these additional gathering facilities totaled $33.9 million. We continue to work with Elevation’s financing partner in constructive discussions surrounding this target completion date.

In addition, upon the occurrence of certain budget overruns with respect to the Elevation facilities or failures of certain facilities to be in operation by the required completion date (each a “Triggering Event”), the Purchaser will have the right, in its sole discretion, to among other remedies, take control of Elevation by removing our subsidiary as the manager of Elevation under Elevation’s management services agreement and/or appointing a majority of the directors of Elevation’s board. If a Triggering Event occurs and the Purchaser were to exercise its right to take control of Elevation, the Purchaser may cause Elevation to complete the development and construction of gathering facilities in a manner that is less beneficial to us than if we continued to control Elevation, transfer its interests in Elevation to a third party and/or sell the gathering facilities to a third party. In addition, if Purchaser were to take control of Elevation, we may no longer be permitted to consolidate Elevation in our financial statements. The failure to meet any of our commitments under the Elevation Gathering Agreements or Elevation’s limited liability company agreement and any resulting incurrence of additional costs, or loss of control of Elevation, could have a material adverse effect on our business, financial condition and results of operations.

The prices we receive for our production may be affected by local and regional factors.

The prices we receive for our production will be determined to a significant extent by factors affecting the local and regional supply of and demand for oil and natural gas, including the adequacy of the pipeline and processing infrastructure in the region to process, and transport, our production and that of other producers. Those factors result in basis differentials between the published indices generally used to establish the price received for regional oil and natural gas production and the actual price we receive for our production, which may be lower than index prices. If the price differentials pursuant to which our production is subject were to widen due to oversupply or other factors, our revenue could be negatively impacted.

Extreme weather conditions could adversely affect our ability to conduct drilling activities in the areas where we operate.

Our exploration, exploitation and development activities and equipment could be adversely affected by extreme weather conditions, such as winter storms, which may cause a loss of production from temporary cessation of activity or lost or damaged facilities and equipment. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

SEC rules could limit our ability to book additional PUDs in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. Moreover, we may be required to write down our PUDs if we do not drill or plan on delaying those wells within the required five-year timeframe. For example, for the year ended December 31, 2019, we wrote down approximately 69,731 MBoe of PUDs.

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

At December 31, 2019, approximately 44% of our total estimated proved reserves were classified as proved undeveloped. The development of our estimated proved undeveloped reserves of 110,957 MBoe will require an estimated $758.2 million of development capital over the next five years.

Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast, as well as access to liquidity sources, such as the capital markets, our revolving credit facility and derivative contracts. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 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 undeveloped reserves as unproved reserves.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

We own non-operating interests in properties developed and operated by third parties, and as a result, we are unable to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other similar contractual arrangements.

As a participant in these operations, we may not be able to maximize the value associated with these properties in the manner we believe appropriate, or at all. For example, we cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator's operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator's failure to adequately perform operations, breach of the applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. 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 such as lease expirations, changes in drilling plans and adverse drilling results, we may be required to write down the carrying value of our properties. A write down constitutes a non-cash charge to earnings. For the year ended December 31, 2019, we recorded non-cash impairment charges of approximately $1.3 billion on proved oil and gas properties primarily in our Core DJ Basin field and if market or other economic conditions deteriorate or if oil, natural gas and NGL prices continue to decline, we may incur impairment charges in 2020 or later periods, which may have a material adverse effect on our results of operations.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Conservation measures and technological advances could reduce demand for oil, natural gas and NGL.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil, natural gas and NGL, technological advances in fuel economy and energy generation devices could reduce demand for oil, natural gas and NGL. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil, natural gas and NGL we produce.

The availability of a ready market for any oil, natural gas and NGL we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of oil and gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. See "Business—Operations—Marketing and Customers." We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production.

The inability of one or more of our purchasers to meet their obligations may adversely affect our financial results.

We have exposure to credit risk through receivables from purchasers of our oil, natural gas and NGL production. One, two and three purchasers accounted for more than 10% of our revenues in the years ended December 31, 2019, 2018 and 2017, respectively. This concentration of purchasers may impact our overall credit risk in that these entities may be similarly affected by changes in economic conditions or commodity price fluctuations. We do not require our customers to post collateral. The inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial condition and results of operations.

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, pipeline and tank ruptures or unauthorized discharges of toxic gases or other pollutants.

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

- 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.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Also, pollution and other environmental risks generally are not fully insurable. The occurrence of an event that is not covered or fully covered by insurance and any delay in the payment of insurance proceeds for covered events could have a material adverse effect on our business, financial condition and results of operations.

Properties that we decide to drill may not yield oil, natural gas or NGL in commercially viable quantities.

Properties that we decide to drill that do not yield oil, natural gas or NGL in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;

- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may be unable to make accretive acquisitions or successfully integrate acquired businesses or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

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

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

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

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our debt arrangements will impose certain limitations on our ability to enter into mergers or combination transactions. Our debt arrangements will also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or land men who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We are subject to stringent environmental and health and safety laws and regulations that could expose us to significant costs and liabilities.

Our oil and natural gas exploration, development and production operations are subject to numerous stringent and complex federal, state and local laws and regulations governing safety and health aspects of our operations, the release, disposal or discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of a permit before conducting drilling and other regulated activities; the restriction of types, quantities and concentration of materials that may be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. 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, often requiring costly actions. For example, on May 2, 2017, following an incident in Firestone, Colorado, the COGCC issued a Notice to Operators (the "Notice") that, among other things, required operators of oil and natural gas wells in Colorado re-inspect and/or properly abandon certain flowlines. On February 13, 2018, the COGCC approved new oil and natural gas flowline requirements, which included flowline tracking, record-keeping, integrity testing, and locking and marking requirements, as well as participation in centralized "call-before-you-dig" system. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory, remedial or corrective obligations, the occurrence of delays in permitting or development of projects and the issuance of orders limiting or prohibiting some or all of our operations in a particular area or forcing future compliance with environmental requirements.

The performance of our operations may result in significant environmental costs and liabilities due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties. Spills or other releases of regulated substances could expose us to material losses, expenditures and liabilities under environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition. We may not be able to recover some or any of our costs with respect to such developments from insurance. See "Business—Regulation of Environmental and Safety and Health Matters" for a further description of environmental and safety and health laws and regulations that affect us.

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

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, natural gas and NGL prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EPAct 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for current violations of up to $1.0 million per day for each violation. FERC's penalty authority is adjusted for inflation from time to time. FERC may also impose administrative and criminal remedies and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and regulations pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the FTC has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1.0 million per day, and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to oil swaps and futures contracts as that granted to the CFTC with respect to oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in "Business—Regulation of the Oil and Gas Industry."

We may be involved in legal proceedings that could result in substantial liabilities.

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

Climate change legislation or regulations restricting emissions of GHG could result in increased operating costs and reduced demand for the oil, natural gas and NGL that we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHG. These efforts have included consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. Additionally, growing attention to climate change risks has resulted in increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business.

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has adopted rules under authority of the CAA that, among other things, establish PSD construction and Title V permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal pollutant emissions, which reviews could require meeting "best available control technology" standards for those emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among other things, onshore producing facilities, which include certain of our operations. Federal agencies also have begun directly regulating emissions of methane from oil and natural gas operations, with the EPA publishing NSPS Subpart OOOOa standards in June 2016 that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions and the BLM publishing requirements in November 2016 to reduce methane emissions from venting, flaring, and leaking on public lands. Both of the EPA and BLM took steps to relax or rescind certain requirements under their respective methane rules. In September 2019, EPA published proposed amendments that would rescind the methane standards and roll back other requirements of the NSPS OOOOa standards and, in September 2018, BLM issued a rule that relaxes or rescinds requirements of its November 2016 regulations. California and New Mexico have challenged BLM's September 2018 rule in ongoing litigation. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France preparing an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In follow-up to an earlier announcement by President Trump, in August 2017, the U.S. Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement and on November 4, 2019, the U.S. submitted formal notification of its withdrawal to the United Nations. The withdrawal will take effect one year from delivery of the notification, although there is a possibility that a new administration could choose to rejoin the Paris Agreement.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHG or otherwise limit emissions of GHG from, our equipment and operations could result in increased costs to reduce emissions of GHG associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil, natural gas and NGL we produce and lower the value of our reserves, which devaluation could be significant. One or more of these developments could have a materially adverse effect on our business, financial condition and results of operations. Finally, notwithstanding potential risks related to climate change, the International Energy Agency, an autonomous intergovernmental organization involved in international energy policy, estimates that global energy demand will continue to rise and will not peak until after 2040 and oil and gas will continue to represent a substantial percentage of global energy use over that time. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Please read "Business-Regulation of Environmental and Safety and Health Matters-Regulation of Greenhouse Gas ("GHG") Emissions" for a further description of the laws and regulations relating to climate change that affect us.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemical additives under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions or similar state agencies but several federal agencies have asserted regulatory authority over certain aspects of the process. In addition, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Also, from time to time, the U.S. Congress has considered, but not adopted, legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. At the state level, Colorado, where we conduct operations, is among the states that has adopted, and other states are considering adopting, regulations that impose new or more stringent permitting, disclosure or well-construction requirements on hydraulic fracturing operations. States may also elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. In addition to state laws, local land use restrictions may restrict drilling or the hydraulic fracturing and cities may adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions but regulating the time, place and manner of those activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, including, for example, on federal and American Indian lands, we could incur potentially significant added cost to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Moreover, because most of our operations are conducted in a particular area, the DJ Basin in Colorado, legal restrictions imposed in that area will have a significantly greater adverse effect than if we had our operations spread out amongst several diverse geographic areas. Consequently, in the event that local or state restrictions or prohibitions are adopted in the DJ Basin in Colorado that impose more stringent limitations on the production and development of oil and natural gas, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the pursuit of exploration, development, or production activities, and possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Any such increased costs, delays, cessations, restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Please read "Business—Regulation of Environmental and Safety and Health Matters—Hydraulic Fracturing Activities" for a further description of the laws and regulations relating to hydraulic fracturing that affect us.

Competition in the oil and natural gas industry and from alternative energy sources is intense, making it more difficult for us to acquire properties and market oil or natural gas.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, and raising additional capital, which could have a material adverse effect on our business.

We also face indirect competition from alternative energy sources, including wind, solar, nuclear and electric power. The proliferation of alternative energy sources and businesses that provide such alternative energy sources may decrease the demand for oil and natural gas products. Decreased demand for our products could adversely affect our business, financial condition, results of operations or cash flows.

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

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

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

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, our leases for such acreage will expire. The cost to renew such leases is substantial and may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. For example, we would incur approximately $103.1 million if we were to extend all of our leases set to expire in the next three years without taking into account the drilling of wells and holding leases by production. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business. Moreover, many of our leases require lessor consent to unitize, which may make it more difficult to hold our leases by production. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. Our reserves and future production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage and the loss of any leases could materially and adversely affect our ability to so develop such acreage. These risks are greater at times and in areas where the pace of our exploration and development activity slows.

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

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the United States financial market have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatile commodity prices, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

The ability or willingness of OPEC and other oil exporting nations to set and maintain production levels has a significant impact on oil and natural gas commodity prices.

OPEC is an intergovernmental organization that seeks to manage the price and supply of oil on the global energy market. Actions taken by OPEC members, including those taken alongside other oil exporting nations, have a significant impact on global oil supply and pricing. For example, OPEC and certain other oil exporting nations have previously agreed to take measures, including production cuts, to support crude oil prices. In March 2020, members of OPEC and Russia considered extending and potentially increasing these oil production cuts. However, these negotiations were unsuccessful. As a result, Saudi Arabia announced an immediate reduction in export prices and Russia announced that all previously agreed oil production cuts will expire on April 1, 2020. These actions led to an immediate and steep decrease in oil prices. There can be no assurance that OPEC members and other oil exporting nations will agree to future production cuts or other actions to support and stabilize oil prices, nor can there be any assurance that they will not further reduce oil prices or increase production. Uncertainty regarding future actions to be taken by OPEC members or other oil exporting countries could lead to increased volatility in the price of oil, which could adversely affect our business, financial condition and results of operations.

Outbreaks of communicable diseases could adversely affect our business, financial condition and results of operations.

Global or national health concerns, including the outbreak of pandemic or contagious disease, can negatively impact the global economy and, therefore, demand and pricing for oil and natural gas products. For example, there have been recent outbreaks in several countries, including the United States, of COVID-19, a highly transmissible and pathogenic coronavirus. The outbreak of communicable diseases, or the perception that such an outbreak could occur, could result in a widespread public health crisis that could adversely affect the economies and financial markets of many countries, resulting in an economic downturn that would negatively impact the demand for oil and natural gas products. Furthermore, uncertainty regarding the impact of any outbreak of pandemic or contagious disease, including COVID-19, could lead to increased volatility in oil and natural gas prices. The occurrence or continuation of any of these events could lead to decreased revenues and limit our ability to execute on our business plan, which could adversely affect our business, financial condition and results of operations.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We are susceptible to the potential difficulties associated with rapid growth and expansion and have a limited operating history.

We have grown rapidly since we began operations in late 2012. Our management believes that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information incorporated herein is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Potential disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

Adverse weather conditions may negatively affect our operating results and our ability to conduct drilling activities.

Adverse weather conditions may cause, among other things, increases in the costs of, and delays in, drilling or completing new wells, power failures, temporary shut-in of production and difficulties in the transportation of our oil, natural gas and NGL. Any decreases in production due to poor weather conditions will have an adverse effect on our revenues, which will in turn negatively affect our cash flow from operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. Drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations from local sources, we may be unable to produce oil, natural gas and NGL economically, which could have an adverse effect on our financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife and natural resources may adversely affect our ability to conduct drilling activities areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife and natural resources. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

The enactment of derivatives legislation and associated regulations 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, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. While many rules implementing the Dodd-Frank Act have been finalized, some have not, and, as a result, the final form of the regulatory regime for commodity derivatives remains uncertain. Position limits for certain energy commodity futures and options contracts, as well as economically equivalent swaps, futures and options, are subject to ongoing rulemaking activities. With regard to position limits, in January 2020, the CFTC withdrew the 2013 proposal, the 2016 supplement, and the 2016 reproposal, and issued a new proposed rule which includes limits on positions in (1) certain "Core Referenced Futures Contracts," including contracts for several energy commodities; (2) futures and options on futures that are directly or indirectly linked to the price of a Core Referenced Futures Contract, or to the same commodity for delivery at the same location as specified in that Core Referenced Futures Contract; and (3) economically equivalent swaps. The proposal also includes exemptions from position limits for bona fide hedging activities. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The Dodd-Frank Act and CFTC rules also will require us, in connection with certain derivatives activities, to comply with clearing and trade-execution requirements (or to take steps to qualify for an exemption to such requirements). In addition, the CFTC and certain banking regulators have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception to the mandatory clearing, trade-execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps we use for hedging. In addition, if any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact our liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow. It is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil, natural gas and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and NGL. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

Recent changes in United States federal income tax law may have an adverse effect on our cash flows, results of operations or financial condition overall.

The final version of the tax reform bill commonly known as the Tax Cuts and Jobs Act (the "TCJA") signed into law on December 22, 2017 may affect our cash flows, results of operations and financial condition. Among other items, the TCJA repealed the deduction for certain U.S. Production activities and provided for a new limitation on the deduction for interest expense. Given the scope of this law and the potential interdependency of its changes, it is difficult at this time to assess whether the overall effect of the TCJA will be cumulatively positive or negative for our earnings and cash flow, but such changes may adversely impact our financial results.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Although none of these changes were included in the TCJA, future adverse changes could 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, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on the Company’s financial position, results of operations and cash flows.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Our business could be negatively affected by security threats, including cybersecurity threats, destructive forms of protest and opposition by activists and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information, to misappropriate financial assets or to render data or systems unusable; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of financial assets, sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability. In addition, destructive forms of protest and opposition by activists and other disruptions, including acts of sabotage or eco-terrorism, against oil and gas production and activities could potentially result in damage or injury to people, property or the environment or lead to extended interruptions of our operations, adversely affecting our financial condition and results of operations.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Risks Related to our Common Stock

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

We completed our initial public offering ("IPO") in October 2016. As a public company, we must comply with various laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act, related regulations of the SEC and the requirements of the NASDAQ, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are now required to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NASDAQ;
- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Moreover, if we are not able to comply with the requirements of Section 404 in a timely manner, or if in the future we or our independent registered public accounting firm identifies deficiencies in our internal controls over financial reporting that are deemed to be material weaknesses, the market price of our stock could decline, and we could be subject to sanctions or investigations by the SEC or other regulatory authorities, which would require additional financial and management resources.

In addition, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

We have restated prior financial statements, which may lead to additional risks and uncertainties, including increased possibility of legal proceedings and loss of investor confidence.

We have restated our condensed consolidated financial statements as of and for the three and nine months ended September 30, 2019 in order to correct an accounting error. As a result of the Restatement, we have become subject to possible additional costs for accounting and legal fees in connection with or related to the restatement and additional risks and uncertainties, including, among others, the increased possibility of legal proceedings, shareholder lawsuits or a review by the SEC and other regulatory bodies, which could cause investors to lose confidence in our reported financial information and could subject us to civil or criminal penalties, shareholder class actions or derivative actions. We could face monetary judgments, penalties or other sanctions that could have a material adverse effect on our business, financial condition and results of operations and could cause our stock price to decline.

We have identified a material weakness in our internal control over financial reporting that, if not remediated, could result in additional material misstatements in our financial statements. If one or more additional material weaknesses emerge related to financial reporting, or if we otherwise fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected. As a result, current and potential stockholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls or to remediate any material weaknesses will be successful, that we will be able to establish and maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common stock.

As a result of the Restatement described in the risk immediately above, management identified a control deficiency that represents a material weakness. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

As of December 31, 2019, we have developed and implemented a remediation plan to address the material weakness which includes additional and enhanced controls to specifically determine the appropriate contract termination date and evaluate the potential accounting implications of changes in termination dates of contracts with customers. If our remediation efforts are insufficient or if additional material weaknesses in our internal control over financial reporting are discovered or occur in the future, our consolidated financial statements may contain material misstatements and we could be required to restate our financial results, which could materially and adversely affect our business, results of operations and financial condition, restrict our ability to access the capital markets, require us to expend significant resources to correct the material weakness, subject us to fines, penalties or judgments, harm our reputation or otherwise cause a decline in investor confidence.

Yorktown's funds collectively hold a substantial portion of the voting power of our common stock.

Yorktown's funds currently collectively hold approximately 36% of our common stock. See "Security Ownership of Certain Beneficial Owners and Management" for more information regarding ownership of our common stock by the Yorktown funds. The existence of affiliated stockholders with significant aggregate holdings that may act as a group may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, this concentration of stock ownership may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with affiliated stockholders with significant aggregate holdings that may act as a group.

If we fail to meet the requirements for continued listing on the NASDAQ Global Select Market, our common stock could be delisted, which would decrease the liquidity of our common stock and our ability to raise additional capital.

Our common stock is currently listed for quotation on the NASDAQ Global Select Market. We are required to meet specified requirements to maintain our listing on the NASDAQ Global Select Market, including, among other things, a minimum bid price of $1.00 per share. From February 14, 2020 to the date of this report, the bid price for our common stock had closed below the minimum $1.00 per share requirement for continued inclusion on the NASDAQ Global Select Market. If we fail to satisfy the NASDAQ Global Select Market's continued listing requirements, we may be delisted and the quotation of our common stock may be transferred to the OTC Bulletin Board. Having our common stock quoted on the OTC Bulletin Board could adversely affect the liquidity of our common stock. Any such transfer could make it more difficult to dispose of, or obtain accurate quotations for the price of, our common stock, and there also would likely be a reduction in our coverage by securities analysts and the news media, which could cause the price of our common stock to decline further. We may also face other material adverse consequences in such event, such as negative publicity, a decreased ability to obtain additional financing, diminished investor and/or employee confidence, and the loss of business development opportunities, any of which may contribute to a further decline in our stock price.

Conflicts of interest could arise in the future between us, on the one hand, and Yorktown and its affiliates, including its funds and their respective portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities.

Yorktown's funds are in the business of making investments in entities in the U.S. energy industry. As a result, Yorktown's funds may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. Yorktown's funds and their respective portfolio companies may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Under our certificate of incorporation, Yorktown's funds and/or one or more of their respective affiliates are permitted to engage in business activities or invest in or acquire businesses which may compete with our business or do business with any client of ours. Any actual or perceived conflicts of interest with respect to the foregoing could have an adverse impact on the trading price of our common stock.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

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 in addition to the Series A 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:

- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders; and
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our bylaws.

We do not intend to pay dividends on our common stock, and our debt arrangements and the Series A Preferred Stock place certain restrictions on our ability to do so. Consequently, it is possible that the only opportunity to achieve a return on an investment in our common stock will be if the price of our common stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, our debt arrangements and the Series A Preferred Stock restrict our ability to pay cash dividends. Consequently, it is possible that the only opportunity to achieve a return on an investment in our common stock will be if shareholders sell their common stock at a price greater than they paid for it. There is no guarantee that the price of our common stock that will prevail in the market will ever exceed the price that such investors paid for our common stock.

Future sales of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute the ownership in us by current shareholders.

We may sell additional shares of common stock in public or private offerings. We may also issue additional shares of common stock or convertible securities. Excluding any shares of common stock issued upon the conversion of our Series A Preferred Stock including any shares of Series A Preferred Stock that may be issued pursuant to our option to pay dividends on the Series A Preferred Stock in kind pursuant to the terms of the Certificate of Designations setting forth the terms of the Series A Preferred Stock, we have 137,657,922 outstanding shares of common stock as of December 31, 2019. In connection with the IPO, we filed a registration statement with the SEC on Form S-8 providing for the registration of 23,000,000 shares of our common stock issued or reserved for issuance under our equity incentive plan. Subject to the satisfaction of vesting conditions, the expiration of lock-up agreements and the requirements of Rule 144, shares registered under the registration statement on Form S-8 will be available for resale immediately in the public market without restriction. Additionally, the Series A Preferred Stock are convertible into shares of our common stock pursuant to their terms.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock.

Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

We may issue additional preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock, including the Series A Preferred Stock, could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

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

Our certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim for a breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, our certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our certificate of incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Exchange Act.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal proceedings and review the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in our best interests. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our business, financial position, results of operations or liquidity.

COGCC Notices of Alleged Violations ("NOAVs"). We have received NOAVs from the COGCC for alleged compliance violations that we have responded to. At this time, the COGCC has not alleged any specific penalty amounts in these matters. We do not believe that any penalties that could result from these NOAVs will have a material effect on our business, financial condition, results of operations or liquidity, but they may exceed $100,000.

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 Information.

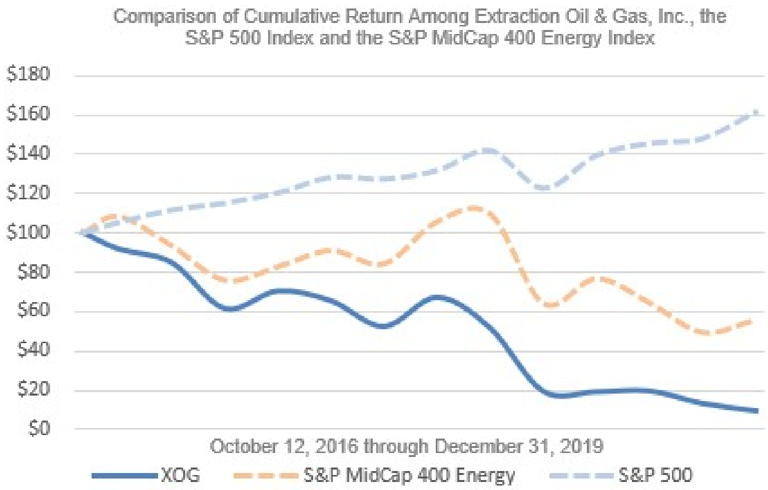
Our common stock is currently traded on the NASDAQ under the ticker symbol "XOG."

Dividend Policy

We have not historically paid, and do not anticipate paying in the future, any cash dividends to holders of our common stock. In addition, our revolving credit facility, our Senior Notes (collectively, our "debt arrangements") and the Series A Preferred Stock place certain restrictions on our ability to pay cash dividends. For more information regarding the restrictions placed on our ability to pay cash dividends, please see *Note 6 — Long Term Debt* included in the notes to the consolidated financial statements included elsewhere in this Annual Report.

Comparison of Cumulative Return

The following graph compares the cumulative total shareholder return on a $100 investment in our common stock on October 12, 2016 through December 31, 2019, to that of the cumulative return on a $100 investment in the S&P MidCap 400 Energy Index and S&P 500 Composite for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purposes only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.



Holders

Pursuant to the records of the transfer agent, as of March 9, 2020 the number of holders of record of our common stock was 58.

Sales of Unregistered Securities

We did not have any sales of unregistered securities during the fiscal year ended December 31, 2019.

Issuer Purchases of Equity Securities

We did not have any share repurchase activity during the three months ended December 31, 2019.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial information should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations" and the consolidated financial statements and the notes thereto included in "Item 8. Financial Statements and Supplementary Data" presented elsewhere in this Annual Report for further discussion of the factors affecting the comparability of the Company's financial data. Also see "Recent Accounting Pronouncements" included in the notes to the consolidated financial statements included elsewhere in this Annual Report. The following table sets forth selected consolidated financial data as of and for the five-years ended December 31, 2019.

	For the Year Ended December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
	(In thousands, except per share data)				
Revenues:					
Oil sales	$ 721,429	$ 840,687	$ 419,904	$ 194,059	$ 157,024
Natural gas sales(1)	108,873	105,629	92,322	48,652	26,019
NGL sales(1)	75,072	114,427	92,070	35,378	14,707
Gathering and compression	1,261	—	—	—	—
Total Revenues	906,635	1,060,743	604,296	278,089	197,750
Operating Expenses:					
Lease operating expenses	97,254	79,413	60,358	36,743	23,949
Midstream operating expenses	2,258	—	—	—	—
Transportation and gathering(1)	53,140	39,411	50,948	25,300	6,679
Production taxes	68,182	90,345	51,367	20,730	17,035
Exploration and abandonment expenses	88,794	31,611	36,256	36,422	18,636
Depletion, depreciation, amortization and accretion	524,537	435,775	314,999	205,348	146,547
Impairment of long lived assets and goodwill	1,337,996	70,928	1,647	23,425	15,778
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	421	(136,834)	451	—	—
Acquisition transaction expenses	—	—	—	2,719	6,000
General and administrative expenses	98,845	134,604	110,167	232,388	37,149
Other operating expenses	—	—	—	10,891	2,353
Total Operating Expenses	2,271,427	745,253	626,193	593,966	274,126
Operating Income (Loss)	(1,364,792)	315,490	(21,897)	(315,877)	(76,376)
Other Income (Expense):					
Commodity derivatives gain (loss)	(37,107)	(8,554)	(36,332)	(100,947)	79,932
Interest expense	(79,232)	(123,330)	(51,889)	(68,843)	(51,030)
Other income	4,535	5,099	2,010	386	210
Total Other Expense	(111,804)	(126,785)	(86,211)	(169,404)	29,112
Income (Loss) Before Income Taxes	(1,476,596)	188,705	(108,108)	(485,281)	(47,264)
Income tax (expense) benefit(2)	109,176	(66,850)	63,700	29,280	—
Net Income (Loss)	$ (1,367,420)	$ 121,855	$ (44,408)	$ (456,001)	$ (47,264)
Net income attributable to noncontrolling interest	19,992	7,287	—	—	—
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	(1,387,412)	114,568	(44,408)	(456,001)	(47,264)
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	(19,436)	(16,869)	(16,279)	(3,999)	—
Net Income (Loss) Available to Common Shareholders, Basic and Diluted	$ (1,406,848)	$ 97,699	$ (60,687)	$ (460,000)	$ (47,264)
Income (Loss) Per Common Share(3)					
Basic and diluted	$ (9.29)	$ 0.56	$ (0.35)	$ (1.54)	

Selected consolidated financial information continued:

	As of and for the Year Ended December 31,				
	2019	2018	2017	2016	2015
Total Production Volumes:					
Oil (MBbls)	15,436	14,679	9,594	5,287	3,946
Natural Gas (MMcf)	64,710	46,847	32,395	20,212	10,823
NGL (MBbls)	6,164	5,260	3,901	2,284	1,335
Total (MBOE)	32,386	27,747	18,894	10,940	7,084
Average net sales (BOE/d)	88,729	76,019	51,764	29,891	19,408
Proved Reserves:					
Oil (MBbls)	91,459	135,846	111,275	90,995	71,500
Natural Gas (MMcf)	580,089	703,268	626,169	507,735	292,584
NGL (MBbls)	66,009	94,851	77,106	62,448	38,383
Total (MBOE)	254,149	347,908	292,743	238,066	158,647
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$ 557,957	$ 684,933	$ 316,965	$ 120,688	$ 166,683
Net cash used in investing activities	$ (850,153)	$ (897,305)	$ (1,404,528)	$ (873,608)	$ (530,077)
Net cash provided by financing activities	$ 89,592	$ 440,590	$ 463,395	$ 1,286,750	$ 371,404
Consolidated Balance Sheet Information:					
Total Assets(4)	$ 2,926,957	$ 4,166,027	$ 3,384,669	$ 2,784,776	$ 1,634,140
Long-term Debt	$ 1,555,777	$ 1,417,659	$ 1,023,361	$ 538,141	$ 637,790
Series A Preferred Stock	$ 175,639	$ 164,367	$ 158,383	$ 153,139	$ —
Total Equity	$ 244,373	$ 1,746,814	$ 1,616,765	$ 1,616,073	$ 754,232
Noncontrolling interest(5)	$ 264,364	$ 147,872	$ —	$ —	$ —
Other Financial Data(6):					
Adjusted EBITDAX	$ 610,726	$ 659,752	$ 380,462	$ 192,265	$ 176,120

(1) As a result of the adoption of ASC 606 on January 1, 2018, certain costs previously classified as transportation and gathering expenses are presented on a net basis for proceeds expected to be received. For additional discussion, please see *Note 2 — Basis of Presentation and Significant Accounting Policies* in Part II, Item 8 of this Annual Report.

(2) Extraction Oil & Gas, Inc. is a subchapter C corporation ("C-Corp") under the Internal Revenue Code of 1986, as amended, and is subject to federal and State of Colorado income taxes. Our predecessor, Extraction Oil & Gas Holdings, LLC was not subject to U.S. federal income taxes. As a result, the consolidated net income (loss) in our historical financial statements for periods prior to our October 12, 2016 corporate reorganization to a C-Corp does not reflect the tax expense we would have incurred as a C-Corp during such periods.

(3) See *Note 10 — Equity* and *Note 13 — Earnings (Loss) Per Share* in Part II, Item 8 of this Annual Report for additional discussion regarding the calculation of income (loss) per share.

(4) As a result of the adoption of ASC 842 on January 1, 2019, certain lease agreements with terms over one year are classified as right-of-use assets and right-of-use liabilities, which gross up the balance sheet. For additional discussion, please see *Note 5 — Leases* in Part II, Item 8 of this Annual Report.

(5) Noncontrolling interest relates to Elevation Preferred Units. For additional discussion, please see *Note 10 — Equity — Preferred Units* in Part II, Item 8 of this Annual Report.

(6) Adjusted EBITDAX is a non-GAAP financial measure. Management defines Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depletion, depreciation, amortization and accretion ("DD&A"), impairment of long lived assets and goodwill, exploration and abandonment expenses, rig termination fees, write off of deposit on acquisition, (gain) loss on sale of property and equipment, gain on sale of assets of unconsolidated subsidiaries, acquisition transaction expenses, (gain) loss on commodity derivatives, settlements on commodity derivative instruments, premiums paid for derivatives that settled during the period, unit and stock-based compensation expense, amortization of debt discount and debt issuance costs, make-whole premiums, gain on repurchase of 2026 Senior Notes, interest expense, income tax expense (benefit) and non-recurring charges. See Part II, Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report for additional disclosures related to Adjusted EBITDAX.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes appearing in "Item 8. Financial Statements and Supplementary Data." The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly in "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

This section of this Form 10-K generally discusses 2019 and 2018 items and year-to-year comparisons between 2019 and 2018. Discussions of 2017 items and year-to-year comparisons between 2018 and 2017 that are not included in this Form 10-K can be found in "Management’s Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and are incorporated herein by reference.

OVERVIEW

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, as well as the construction and support of midstream assets to gather and process crude oil and gas production in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in some of the most productive areas of what we consider to be the core of the DJ Basin. Toward the end of the third quarter and into the fourth quarter of 2019, management elected to shift the corporate strategy from one of maximizing production and reserve growth to one focused on cash flow and reducing debt while improving our liquidity.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as oil and gas prices, economic, political and regulatory developments, competition from other sources of energy, and the other items discussed under the caption “Risk Factors” in Item 1A of this Annual Report. Lower commodity prices may also reduce the amount of the borrowing base under our revolving credit facility, which is determined at the discretion of our lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Upon any redetermination, if total outstanding commitments exceed the redetermined borrowing base, we are required to prepay outstanding loans in an aggregate principal amount equal to such excess in three substantially equal monthly installments.

Our Properties and Operations

We have assembled, as of December 31, 2019, approximately 169,900 net acres of large, contiguous acreage blocks in some of the most productive areas of what we consider to be the core of the DJ Basin as indicated by the results of our horizontal drilling program and the results of offset operators. Additionally, we hold approximately 125,500 net acres outside of what we consider our Core DJ Basin, which we refer to as our "Other Rockies Area," that we believe is prospective for many of the same formations as our properties in the Core DJ Basin. We operated 96% of our horizontal production for the year ended December 31, 2019, our total estimated proved reserves were approximately 254.1 MMBoe, of which approximately 56% were classified as proved developed reserves. For more information about our properties, please read "Business—Our Properties." in Items 1 and 2 of this Annual Report.

Our unrestricted subsidiary, Elevation, is focused on the construction of gathering systems and facilities operations to serve the development of our acreage in the Hawkeye and Southwest Wattenberg areas. Midstream assets of Elevation are represented as the gathering systems and facilities line item within the consolidated balance sheets. In October 2019, Elevation commenced moving crude oil, natural gas and water through its newly constructed Badger central gathering facility. This facility enables Extraction and will enable others to efficiently transport crude oil and natural gas production along with water used during the completion process. The use of this gathering facility allows for the elimination of oil or water storage on the well pad site and reduces truck traffic, which minimizes the impact to the surrounding environment and communities. Revenues and operating expenses associated with the gathering systems and facilities operations are primarily derived from intersegment transactions for services provided to our development and production operations as well as third parties.

Financial Overview

For the year ended December 31, 2019, we had a net loss of $1.4 billion as compared to net income of $121.9 million for the year ended December 31, 2018. The change to net loss was primarily driven by a decrease in sales revenues of $154.1 million, coupled with an increase in operating expenses of $1.5 billion, which includes an increase of $1.3 billion in the impairment of long-lived assets and a decrease in the gain on sale of property and equipment and assets of unconsolidated subsidiary of $137.3 million. Additionally, we had a decrease in interest expense of $44.1 million.

For the year ended December 31, 2019, crude oil, natural gas, NGL sales and gathering and compression revenue, coupled with the impact of settled derivatives, decreased to $881.9 million as compared to $930.1 million in the same prior year period due to a decrease of $6.33 in realized price per BOE, including settled derivatives, offset by an increase in sales volumes of approximately 4,600 MBoe.

Adjusted EBITDAX was $610.7 million for the year ended December 31, 2019, as compared to $659.8 million in the same period in 2018, reflecting a 7% decrease. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "Adjusted EBITDAX."

Operational Overview

During the year ended December 31, 2019, we focused on improving free cash flow and implemented operational efficiencies to reduce drilling and completion costs. We incurred approximately $542.8 million in drilling 107 gross (99.6 net) wells with an average lateral length of 2.0 miles and completing 119 gross (104.3 net) wells with an average lateral length of 1.9 miles, all of which were horizontal wells in the DJ Basin. In addition, we incurred approximately $54.9 million of leasehold and surface acreage additions. In addition, Elevation Midstream, LLC, our midstream subsidiary, incurred $202.6 million of capital expenditures.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and gas operations, including:

- Sources of revenue;
- Sales volumes;
- Realized prices on the sale of oil, natural gas and NGL, including the effect of our commodity derivative contracts;
- Lease operating expenses ("LOE");
- Capital expenditures;
- Adjusted EBITDAX (a Non-GAAP measure); and
- Free cash flow (a Non-GAAP measure).

Sources of Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGL that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the year ended December 31, 2019, our revenues were derived 80% from oil sales, 12% from natural gas sales and 8% from NGL sales. For the year ended December 31, 2018, our revenues were derived 79% from oil sales, 10% from natural gas sales and 11% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

The following table presents historical sales volumes for the periods indicated:

	For the Year Ended December 31,	
	2019	2018
Oil (MBbl)	15,436	14,679
Natural gas (MMcf)	64,710	46,847
NGL (MBbl)	6,164	5,260
Total (MBoe)	32,386	27,747
Average net sales (BOE/d)	88,728	76,019

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add or develop proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through organic growth as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including takeaway capacity in our areas of operation and our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read "Risks Related to the Oil, Natural Gas and NGL Industry and Our Business" in Item 1A. of this Annual Report for a further description of the risks that affect us.

Realized Prices on the Sale of Oil, Natural Gas and NGL

Our results of operations depend upon many factors, particularly the price of oil, natural gas and NGL and our ability to market our production effectively. Oil, natural gas and NGL prices are among the most volatile of all commodity prices. Declines in, and continued depression of, the price of oil and natural gas occurring during 2018 and 2019 are due to a combination of factors including increased U.S. supply, global economic concerns and geopolitical risks. These price variations can have a material impact on our financial results and capital expenditures.

Oil pricing is predominately driven by the physical market, supply and demand, financial markets and national and international politics. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. In the DJ Basin, oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant, generally in the form of percentage of proceeds. The price we receive for our natural gas produced in the DJ Basin is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the DJ Basin is based on a combination of prices from the Conway hub in Kansas and Mont Belvieu in Texas where this production is marketed.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil, natural gas and NGL normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, as applicable.

	For the Year Ended December 31,	
	2019	2018
Oil		
NYMEX WTI High ($/Bbl)	$ 66.30	$ 76.41
NYMEX WTI Low ($/Bbl)	$ 46.54	$ 42.53
NYMEX WTI Average ($/Bbl)	$ 57.04	$ 64.90
Average Realized Price ($/Bbl)(1)	$ 46.74	$ 57.27
Average Realized Price, with derivative settlements ($/Bbl)(1)	$ 45.16	$ 48.04
Average Realized Price as a % of Average NYMEX WTI	81.9 %	88.2 %
Differential ($/Bbl) to Average NYMEX WTI(2)	$ (8.71)	$ (7.63)
Natural Gas		
NYMEX Henry Hub High ($/MMBtu)	$ 3.59	$ 4.84
NYMEX Henry Hub Low ($/MMBtu)	$ 2.07	$ 2.55
NYMEX Henry Hub Average ($/MMBtu)(3)	$ 2.78	$ 3.07
Average Realized Price ($/Mcf)	$ 1.68	$ 2.25
Average Realized Price, with derivative settlements ($/Mcf)	$ 1.68	$ 2.36
Average Realized Price as a % of Average NYMEX Henry Hub(3)	60.4 %	66.7 %
Differential ($/Mcf) to Average NYMEX Henry Hub(3)	$ (1.10)	$ (1.12)
NGL		
Average Realized Price ($/Bbl)(4)	$ 12.18	$ 21.75
Average Realized Price as a % of Average NYMEX WTI	21.4 %	33.5 %

(1) Includes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the year ended December 31, 2019, pursuant to ASC 606, Revenue Recognition.

(2) Excludes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the year ended December 31, 2019, pursuant to ASC 606, Revenue Recognition.

(3) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.

(4) The decrease year over year is primarily due to capacity constraints in transporting the wet gas associated with our production coupled with negative market conditions surrounding limited export capacity.

Derivative Arrangements

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our oil and natural gas production. By removing a significant portion of price volatility associated with our oil and natural gas production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. See "—Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. As a result of recent volatility in the price of oil and natural gas, we have relied on a variety of hedging strategies and instruments to hedge our future price risk. We have utilized swaps, put options, and call options, which in some instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of our purchased put options have deferred premiums. For the deferred premium puts, we agreed to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We combine swaps, purchased put options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap. We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices.

We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements at favorable prices may be limited, and we are not obligated to hedge a specific portion of our oil or natural gas production. The following summarizes our net derivative positions related to crude oil and natural gas sales in effect as of December 31, 2019:

	2020	2021	2022	2023
NYMEX WTI Crude Swaps:				
Notional volume (Bbl)	3,200,000	3,900,000	1,020,000	900,000
Weighted average fixed price ($/Bbl)	$ 59.81	$ 57.17	$ 54.84	$ 54.87
NYMEX WTI Crude Purchased Puts:				
Notional volume (Bbl)	9,725,000	3,600,000	—	—
Weighted average purchased put price ($/Bbl)	$ 54.99	$ 54.17	$ —	$ —
NYMEX WTI Crude Sold Calls:				
Notional volume (Bbl)	9,725,000	3,600,000	—	—
Weighted average sold call price ($/Bbl)	$ 62.04	$ 61.93	$ —	$ —
NYMEX WTI Crude Sold Puts:				
Notional volume (Bbl)	12,250,000	7,500,000	600,000	600,000
Weighted average sold put price ($/Bbl)	$ 42.91	$ 43.28	$ 43.00	$ 43.00
NYMEX HH Natural Gas Swaps:				
Notional volume (MMBtu)	35,400,000	—	—	—
Weighted average fixed price ($/MMBtu)	$ 2.75	$ —	$ —	$ —
NYMEX HH Natural Gas Purchased Puts:				
Notional volume (MMBtu)	600,000	—	—	—
Weighted average purchased put price ($/MMBtu)	$ 2.90	$ —	$ —	$ —
NYMEX HH Natural Gas Sold Calls:				
Notional volume (MMBtu)	600,000	—	—	—
Weighted average sold call price ($/MMBtu)	$ 3.48	$ —	$ —	$ —
CIG Basis Gas Swaps:				
Notional volume (MMBtu)	45,600,000	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.61)	$ —	$ —	$ —

The following table summarizes our historical derivative positions and the settlement amounts for each of the periods indicated.

	For the Year Ended December 31,	
	2019	2018
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	9,830,000	5,050,000
Weighted average fixed price ($/Bbl)	$ 53.08	$ 51.58
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	22,050,000	12,327,600
Weighted average strike price ($/Bbl)	$ 46.87	$ 44.81
NYMEX WTI Crude Purchased Calls:		
Notional volume (Bbl)	18,350,000	2,850,000
Weighted average strike price ($/Bbl)	$ 65.74	$ 58.41
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	22,300,000	10,090,000
Weighted average strike price ($/Bbl)	$ 64.57	$ 57.46
NYMEX WTI Crude Sold Puts:		
Notional volume (Bbl)	22,350,000	13,388,800
Weighted average strike price ($/Bbl)	$ 45.11	$ 39.09
NYMEX HH Natural Gas Swaps:		
Notional volume (MMBtu)	32,400,000	40,650,000
Weighted average fixed price ($/MMBtu)	$ 2.81	$ 3.10
NYMEX HH Natural Gas Purchased Puts:		
Notional volume (MMBtu)	3,600,000	2,400,000
Weighted average purchased put price ($/MMBtu)	$ 3.04	$ 3.00
NYMEX HH Natural Gas Sold Calls:		
Notional volume (MMBtu)	3,600,000	2,400,000
Weighted average sold call price ($/MMBtu)	$ 3.46	$ 3.15
NYMEX HH Natural Gas Sold Puts:		
Notional volume (MMBtu)	3,000,000	—
Weighted average sold call price ($/MMBtu)	$ 2.50	$ —
CIG Basis Gas Swaps:		
Notional volume (MMBtu)	42,200,000	37,935,000
Weighted average fixed basis price ($/MMBtu)	$ (0.73)	$ (0.62)
Total Amounts Received/(Paid) from Settlement (in thousands)	**$ (5,790)**	**$ (123,518)**
Cash provided by (used in) changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$ 5,112	$ (11,106)
Cash Settlements on Commodity Derivatives per Consolidated Statements of Cash Flows	**$ (678)**	**$ (134,624)**

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constitutes part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, water injection and disposal costs, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

Capital Expenditures

For the year ended December 31, 2019, we incurred approximately $542.8 million in drilling and completion capital expenditures. For the year ended December 31, 2019, we drilled 107 gross (99.6 net) wells with an average lateral length of approximately 2.0 miles and completed 119 gross (104.3 net) wells with an average lateral length of approximately 1.9 miles. We turned to sales 115 gross (101.9 net) wells with an average lateral length of approximately 1.8 miles. In addition, we incurred approximately $54.9 million of leasehold and surface acreage additions. In addition, Elevation, our midstream subsidiary, incurred $202.6 million of capital expenditures for the year ended December 31, 2019.

Our 2020 capital budget for the drilling and completion of operated and non-operated wells is approximately $425 million to $475 million, substantially all of which we intend to allocate to the Core DJ Basin. We expect to drill 86 gross operated wells, complete 86 gross operated wells and turn-in-line 92 gross operated wells. Our capital budget anticipates a one to two operated rig drilling program and excludes up to $50 million for Elevation, a portion of which will be funded by Extraction.

The amount and timing of these capital expenditures is within our control and subject to our management’s discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by United States generally accepted accounting principles ("GAAP"). Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depletion, depreciation, amortization and accretion, impairment of long lived assets and goodwill, exploration and abandonment expenses, gain (loss) on sale of property and equipment and assets of unconsolidated subsidiary, (gain) loss on commodity derivatives, settlements on commodity derivative instruments, premiums paid for derivatives that settled during the period, stock-based compensation expense, amortization of debt issuance costs, make-whole premiums on 2021 Senior Notes, gain on repurchase of 2026 Senior Notes, interest expense, and income tax (benefit) expense. Adjusted EBITDAX is also used to evaluate the performance of reportable segments. See *Note 18 — Segment Information* in Part II, Item 8 of this Annual Report for more information regarding the EBITDAX of reportable segments.

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital, hedging strategy and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance. Additionally, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure (i) is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, among other factors; (ii) helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and (iii) is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated (in thousands).

	For the Year Ended December 31, 2019	For the Year Ended December 31, 2018
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:		
Net Income (Loss)	$ (1,367,420)	$ 121,855
Add back:		
Depletion, depreciation, amortization and accretion	524,537	435,775
Impairment of long lived assets and goodwill	1,337,996	70,928
Exploration and abandonment expenses	88,794	31,611
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	421	(136,834)
Loss on commodity derivatives	37,107	8,554
Settlements on commodity derivative instruments	(5,790)	(123,518)
Premiums paid for derivatives that settled during the period	(18,929)	(7,148)
Stock-based compensation expense	43,954	68,349
Amortization of debt discount and debt issuance costs	5,482	13,249
Make-whole premium on 2021 Senior Notes	—	35,600
Gain on repurchase of 2026 Senior Notes	(10,486)	—
Interest expense	84,236	74,481
Income tax (benefit) expense	(109,176)	66,850
Adjusted EBITDAX	$ 610,726	$ 659,752

Free Cash Flow

Our Free Cash Flow is not a measure of net income (loss) as determined by GAAP. We define Free Cash Flow as Discretionary Cash Flow (non-GAAP) less Adjusted Cash Flow used in Investing (non-GAAP) adjusted for Other Non-Recurring Adjustments (non-GAAP). Discretionary Cash Flow is defined as net cash provided by operating activities (GAAP) less changes in working capital (current assets and liabilities). Adjusted Cash Flow used in Investing is defined as cash flow used in investing activities (GAAP) adjusted for changes in accounts payable and accrued liabilities related to capital expenditures.

Free Cash Flow is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Free Cash Flow can provide additional transparency into the drivers of trends in our operating cash flows, such as production, realized sales prices and operating costs, as it disregards the timing of settlement of operating assets and liabilities. We believe Free Cash Flow provides additional information that may be useful in an analysis of our ability to generate cash to fund exploration and development activities, construct and support midstream assets, and to return capital to stockholders.

The following tables present a reconciliation of Discretionary Cash Flow and Free Cash Flow to the GAAP financial measure of net cash provided by operating activities for each of the periods indicated.

	Upstream	Midstream	Consolidated
	For the Year Ended December 31, 2019		
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 554,171	$ 3,786	$ 557,957
Changes in current assets and liabilities	10,589	829	11,418
Discretionary Cash Flow	$ 564,760	$ 4,615	$ 569,375
Cash Flow from Investing Activities			
Net cash used in investing activities	$ (623,506)	$ (226,647)	$ (850,153)
Change in accounts payable and accrued liabilities related to capital expenditures	23,372	428	23,800
Adjusted Cash Flow used in Investing	$ (600,134)	$ (226,219)	$ (826,353)
Other Non-Recurring Adjustments(1)	$ 16,496	$ —	$ 16,496
Free Cash Flow	$ (18,878)	$ (221,604)	$ (240,482)

	Upstream	Midstream	Consolidated
	For the Year Ended December 31, 2018		
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 683,968	$ 965	$ 684,933
Changes in current assets and liabilities	(132,467)	(638)	(133,105)
Discretionary Cash Flow	$ 551,501	$ 327	$ 551,828
Cash Flow from Investing Activities			
Net cash used in investing activities	$ (887,445)	$ (9,860)	$ (897,305)
Change in accounts payable and accrued liabilities related to capital expenditures	38,637	(29,018)	9,619
Adjusted Cash Flow used in Investing	$ (848,808)	$ (38,878)	$ (887,686)
Other Non-Recurring Adjustments(1)	$ 2,349	$ —	$ 2,349
Free Cash Flow	$ (294,958)	$ (38,551)	$ (333,509)

(1) Amount incurred for the construction of our field office that is included in other property and equipment in our consolidated statements of cash flows.

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- On January 1, 2019, we adopted ASC 842 - *Leases*. We adopted using the modified retrospective transition approach to apply the new standard to all leases entered into on or after January 1, 2019 and all existing leases. ASC 842 supersedes previous lease recognition requirements in ASC 840 and resulted in the recognition of $29.2 million of right-of-use assets and $34.6 million of lease liabilities on the consolidated balance sheet as of December 31, 2019. See *Note 5—Leases* in Part II, Item 8 of this Annual Report for more information.

- For the years ended December 31, 2019 and 2018, respectively, exploration and abandonment expenses increased primarily due to the abandonment and impairment of $73.7 million and $25.7 million of unproved properties.

- For the years ended December 31, 2019 and 2018 we recognized $14.5 million and $16.2 million, respectively, in impairment expense on our proved oil and gas properties related to assets in our northern field.

- For the year ended December 31, 2019, we recognized $1.3 billion in impairment expense on our proved oil and gas properties related to assets in our Core DJ Basin field. No impairment expense was recognized for the years ended December 31, 2018 on proved oil and gas properties in our Core DJ Basin field.

- For the year ended December 31, 2018, we fully impaired our goodwill and recognized $54.2 million of impairment expense.

- For the year ended December 31, 2019, we had an insignificant net loss from divestitures, whereas, in 2018 we realized a gain of $136.8 million from the sale of property and equipment and assets of our unconsolidated subsidiary.

Historical Results of Operations and Operating Expenses

Oil, Natural Gas and NGL Sales Revenues, Operating Expenses and Other Income (Expense).

The following table provides the components of our consolidated revenues, operating expenses, other income (expense) and net income (loss) for the periods indicated (in thousands):

	For the Year Ended December 31,	
	2019	**2018**
Revenues:		
Oil sales	$ 721,429	$ 840,687
Natural gas sales	108,873	105,629
NGL sales	75,072	114,427
Gathering and compression	1,261	—
Total Revenues	906,635	1,060,743
Operating Expenses:		
Lease operating expenses	97,254	79,413
Midstream operating expenses	2,258	—
Transportation and gathering	53,140	39,411
Production taxes	68,182	90,345
Exploration and abandonment expenses	88,794	31,611
Depletion, depreciation, amortization and accretion	524,537	435,775
Impairment of long lived assets and goodwill	1,337,996	70,928
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	421	(136,834)
General and administrative expenses	98,845	134,604
Total Operating Expenses	2,271,427	745,253
Operating Income (Loss)	(1,364,792)	315,490
Other Income (Expense):		
Commodity derivatives loss	(37,107)	(8,554)
Interest expense	(79,232)	(123,330)
Other income	4,535	5,099
Total Other Expense	(111,804)	(126,785)
Income (Loss) Before Income Taxes	(1,476,596)	188,705
Income tax benefit (expense)	109,176	(66,850)
Net Income (Loss)	$ (1,367,420)	$ 121,855

The following table provides a summary of our sales volumes, average prices and operating expenses on a per BOE basis for the periods indicated:

	For the Year Ended December 31,	
	2019	2018
Sales (MBoe)(1):	32,385	27,747
Oil sales (MBbl)	15,436	14,679
Natural gas sales (MMcf)	64,710	46,847
NGL sales (MBbl)	6,164	5,260
Sales (BOE/d)(1):	88,728	76,019
Oil sales (Bbl/d)	42,291	40,217
Natural gas sales (Mcf/d)	177,288	128,347
NGL sales (Bbl/d)	16,889	14,411
Average sales prices(2):		
Oil sales (per Bbl)(3)	$ 46.74	$ 57.27
Oil sales with derivative settlements (per Bbl)(3)	45.16	48.04
Natural gas sales (per Mcf)	1.68	2.25
Natural gas sales with derivative settlements (per Mcf)	1.68	2.36
NGL sales (per Bbl)	12.18	21.75
Average price (per BOE)(3)	27.96	38.23
Average price with derivative settlements (per BOE)(3)	27.19	33.52
Expense per BOE(1):		
Lease operating expenses	$ 3.00	$ 2.86
Transportation and gathering	1.64	1.42
Production taxes	2.11	3.26
Exploration and abandonment expenses	2.74	1.14
Depletion, depreciation, amortization, and accretion	16.20	15.71
General and administrative expenses	3.05	4.85
Cash general and administrative expenses(4)	1.69	2.39
Stock-based compensation	1.36	2.46
Total operating expenses per BOE(5)	28.81	31.80
Production taxes as a percentage of revenue	7.5 %	8.5 %

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.
(2) Average prices shown in the table reflect prices both before and after the effects of our settlements of our commodity derivative contracts. Our calculation of such effects includes both gains and losses on cash settlements for commodity derivatives and premiums paid or received on options that settled during the period.
(3) Includes amounts allocated to a satisfied performance obligation, recognized within oil sales for the year ended December 31, 2019, pursuant to ASC 606, Revenue Recognition.
(4) Cash general and administrative expenses for the year ended December 31, 2019 includes expense of $2.3 million related to the terms of separation agreements with two former executive officers. Excluding these one-time expenses results in cash general and administrative expense per BOE of $1.62 for the year ended December 31, 2019.
(5) Excludes (gain) loss on sale of property and equipment and assets of unconsolidated subsidiary and impairment of long lived assets and goodwill.

Year Ended December 31, 2019 Compared to Year Ended December 31, 2018

Oil sales revenues. Crude oil sales revenues decreased by $119.3 million to $721.4 million for the year ended December 31, 2019 as compared to crude oil sales of $840.7 million for the year ended December 31, 2018. An increase in sales volumes between these periods contributed to a $43.3 million positive impact, while a decrease in crude oil prices contributed a $162.6 million negative impact. For the year ended December 31, 2019 crude oil revenue also decreased by approximately $24.7 million due to the impact of our updated strategy to emphasize free cash flow in 2020 and beyond, resulting in a decrease in future capital expenditures and number of rigs, which decreased the future forecasted production and increased the forecasted deferral balance on one of our revenue contracts. Pursuant to ASC 606, the contract term impacts the amount of consideration that can be included in the transaction price, which reduced oil sales revenue.

For the year ended December 31, 2019, our crude oil sales averaged 42.3 MBbl/d. Our crude oil sales volumes increased 5% to 15,436 MBbl for the year ended December 31, 2019 compared to 14,679 MBbl for the year ended December 31, 2018. The volume increase was primarily due to an increase in production from the completion of 119 wells for the year ended December 31, 2019. The increased production from these new wells was partially offset by the natural decline of our existing producing properties.

The average price we realized on the sale of crude oil was $46.74 per Bbl for the year ended December 31, 2019 compared to $57.27 per Bbl for the year ended December 31, 2018, primarily due to changes in market prices for crude oil and the $24.7 million decrease of crude oil revenue explained above.

Natural gas sales revenues. Natural gas sales revenues increased by $3.3 million to $108.9 million for the year ended December 31, 2019 as compared to natural gas sales revenues of $105.6 million for the year ended December 31, 2018. An increase in sales volumes between these periods contributed a $40.3 million positive impact, while a decrease in natural gas prices contributed a $37.0 million negative impact.

For the year ended December 31, 2019, our natural gas sales averaged 177.3 MMcf/d. Natural gas sales volumes increased by 38% to 64,710 MMcf for the year ended December 31, 2019 as compared to 46,847 MMcf for the year ended December 31, 2018. The volume increase was primarily due to the completion of 119 gross wells for the year ended December 31, 2019. The increased production from these new wells was partially offset by the natural decline of our existing producing properties.

The average price we realized on the sale of our natural gas was $1.68 per Mcf for the year ended December 31, 2019 compared to $2.25 per Mcf for the year ended December 31, 2018, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

NGL sales revenues. NGL sales revenues decreased by $39.3 million to $75.1 million for the year ended December 31, 2019 as compared to NGL sales revenues of $114.4 million for the year ended December 31, 2018. An increase in sales volumes between these periods contributed a $19.7 million positive impact, while a decrease in price contributed a $59.0 million negative impact.

For the year ended December 31, 2019, our NGL sales averaged 16.9 MBbl/d. NGL sales volumes increased by 17% to 6,164 MBbl for the year ended December 31, 2019 as compared to 5,260 MBbl for the year ended December 31, 2018. The volume increase is primarily due to the completion of 119 gross wells for the year ended December 31, 2019. The increased production from these new wells was partially offset by the natural decline of our existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $12.18 per Bbl for the year ended December 31, 2019 compared to $21.75 per Bbl for the year ended December 31, 2018, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

Lease operating expenses ("LOE"). Our LOE, increased by $17.9 million to $97.3 million for the year ended December 31, 2019, from $79.4 million for the year ended December 31, 2018. The increase in LOE was primarily the result of an increase in producing wells and an increase in workover repairs, partially offset by optimization of our field cost structure for the year ended December 31, 2019. On a per unit basis, LOE increased to $3.00 per BOE sold for the year ended December 31, 2019 from $2.86 per BOE sold for the year ended December 31, 2018.

Transportation and gathering. Our T&G expense increased by $13.7 million to $53.1 million for the year ended December 31, 2019, from $39.4 million for the year ended December 31, 2018. The increase in T&G is primarily attributable to an increase in producing wells and in both residue natural gas and NGL sales volumes.

On a per unit basis, T&G increased to $1.64 per BOE sold for the year ended December 31, 2019 from $1.42 per BOE sold for the year ended December 31, 2018.

Production taxes. Our production taxes decreased by $22.1 million to $68.2 million for the year ended December 31, 2019 as compared to $90.3 million for the year ended December 31, 2018. The decrease was attributable to decreased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 7.5% for the year ended December 31, 2019 as compared to 8.5% for the year ended December 31, 2018. The decrease in production taxes as a percentage of sales revenue relates to a decrease in the estimated ad valorem and severance tax rates and an adjustment to the estimated ad valorem tax payable for the year ended December 31, 2019.

Exploration and abandonment expenses. Our exploration and abandonment expenses were $88.8 million and $31.6 million for the years ended December 31, 2019 and 2018, respectively. We recognized $12.4 million in expense attributable to the extension of certain leases and $73.7 million in expense attributable to the abandonment and impairment of unproved properties for the year ended December 31, 2019. We recognized $4.6 million in expense attributable to the extension of certain leases and $25.7 million in expense attributable to the abandonment and impairment of unproved properties for the year ended December 31, 2018.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense increased $88.7 million to $524.5 million for the year ended December 31, 2019 as compared to $435.8 million for the year ended December 31, 2018. This increase was due to an increase in the volumes sold for the year ended December 31, 2019 as sales increased by approximately 4,600 MBoe. On a per unit basis, DD&A expense increased from $15.71 per BOE for the year ended December 31, 2018 to $16.20 per BOE for the year ended December 31, 2019.

Impairment of long lived assets and goodwill. For the year ended December 31, 2019, our impairment expense was $1.3 billion. We recognized $14.5 million related to impairment of the proved oil and gas properties in our northern field and $1.3 billion related to assets in our Core DJ Basin field as the field's fair values did not exceed the carrying amounts associated with our proved oil and gas properties. For the year ended December 31, 2018, our impairment expense was $70.9 million. We recognized $16.2 million related to impairment of the proved oil and gas properties in our northern field as the fair value did not exceed the carrying amount associated with our proved oil and gas properties in our northern field. No impairment expense was recognized for the year ended December 31, 2018 on proved oil and gas properties in our Core DJ Basin field. For the year ended December 31, 2018, we also recognized impairment on goodwill of $54.2 million upon completion of our quantitative assessment noting the fair value of the reporting unit was not greater than its carrying amount.

(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary. Our loss on the sale of insignificant property was $0.4 million for the year ended December 31, 2019, which was related to our March 2019 Divestiture, August 2019 Divestiture and December 2019 Divestitures, as compared to $136.8 million gain on the sale of property and equipment and assets of unconsolidated subsidiary for the year ended December 31, 2018.

General and administrative expenses ("G&A"). General and administrative expenses decreased by $35.8 million to $98.8 million for the year ended December 31, 2019 as compared to $134.6 million for the year ended December 31, 2018. This decrease was primarily due to a decrease of $24.4 million in stock based compensation offset by an increase in employed workforce of 16%, or 44 additional employees during the year ended December 31, 2019 compared to the year ended December 31, 2018. On a per unit basis, G&A expenses decreased by $1.80 per BOE from $4.85 per BOE sold for the year ended December 31, 2018 to $3.05 per BOE sold for the year ended December 31, 2019.

Our G&A expenses include the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the year ended December 31, 2019, stock-based compensation expense was $44.0 million as compared to stock-based compensation expense of $68.3 million for the year ended December 31, 2018. On a per unit basis, stock-based compensation decreased $1.10 per BOE from $2.46 per BOE sold for the year ended December 31, 2018 to $1.36 per BOE sold for the year ended December 31, 2019.

Commodity derivative loss. Primarily due to the increase in NYMEX crude oil futures prices at December 31, 2019 as compared to December 31, 2018 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $37.1 million for the year ended December 31, 2019. Primarily due to the change in fair value from the execution of new positions during the year ended December 31, 2018, partially offset by a decrease in NYMEX crude oil futures prices at December 31, 2018 as compared to December 31, 2017, we incurred a net loss on our commodity derivatives of $8.6 million. These losses are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. For the year ended December 31, 2019 and 2018, we paid cash settlements of commodity derivatives totaling $5.8 million and $123.5 million, respectively.

Interest expense. Interest expense consists of interest expense on our long-term debt and debt issuance costs, net of capitalized interest. For the year ended December 31, 2019, we recognized interest expense of approximately $79.2 million as compared to $123.3 million for the year ended December 31, 2018, as a result of borrowings under our revolving credit facility, our 2021 Senior Notes and the associated make-whole premium and accelerated amortization of debt issuance costs upon redemption, our 2024 Senior Notes, our 2026 Senior Notes, and the amortization of other debt issuance costs.

We incurred interest expense for the year ended December 31, 2019 of approximately $91.5 million related to our 2024 Senior Notes, 2026 Senior Notes and credit facility. We incurred interest expense for the year ended December 31, 2018 of approximately $82.7 million related to our 2021 Senior Notes, 2024 Senior Notes, 2026 Senior Notes and credit facility, as well as a make-whole premium of $35.6 million related to our repayment of our 2021 Senior Notes in January and February 2018. Also included in interest expense for the years ended December 31, 2019 and 2018 was the amortization of debt issuance costs of $5.5 million and $13.2 million, respectively, and a gain on the sale of extinguishment of debt of $10.5 million for the year ended December 31, 2019. Amortization expense for the year ended December 31, 2018 includes $9.4 million of acceleration of amortization expense upon the repayment of our 2021 Senior Notes. For the years ended December 31, 2019 and 2018, we capitalized interest expense of $7.2 million and $8.2 million, respectively.

Income tax (expense) benefit. We recorded income tax benefit of approximately $109.2 million and income tax expense of approximately $66.9 million resulting in an effective tax rate of approximately 7.4% and 35.4% for the years ended December 31, 2019 and 2018, respectively. Our effective tax rate for 2019 differs from the U.S. statutory income tax rate of 21% primarily due to the effects of state income taxes, estimated permanent taxable differences, including partnership income allocated to a noncontrolling interest owner, nondeductible stock-based compensation, and the recording of a valuation allowance against deferred tax assets.

Gathering and facilities segment. We have two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction, operation and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Prior to the fourth quarter of 2018, the Company had a single operating segment.

On October 3, 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility. Because Elevation had no revenue and insignificant operating expenses for the year ended 2018, comparison to the year ended 2019 is not relevant. For the year ended December 31, 2019, our gathering and facilities segment had revenues of $6.9 million and direct operating expenses of $2.3 million. General and administrative expenses were $4.6 million and $2.8 million for the year ended December 31, 2019 compared to the same period in 2018, respectively, due to the increased activity during 2019 from the gathering facility commencing operations. For the year ended December 31, 2019, depreciation expense was $1.4 million as the gathering facility was placed into service during the fourth quarter of 2019. The gain on sale of unconsolidated subsidiary was $1.0 million for the year ended December 31, 2019, which was related to our August 2018 Divestiture, as compared to $83.6 million gain on the sale of unconsolidated subsidiary for the year ended December 31, 2018. Capital expenditures associated with the gathering systems and facilities segment were incurred to develop midstream infrastructure to support the Company's development of its oil and gas leasehold along with third-party activity and amounted to $202.6 million and $108.2 million for the years ended December 31, 2019 and 2018, respectively. See *Note 16—Segments* in Part II, Item 8 of this Annual Report for more information.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our revolving credit facility. Depending upon market conditions and other factors, we may also issue equity and debt securities, if needed.

Historically, our primary sources of liquidity have been borrowings under our revolving credit facility, proceeds from notes offerings, equity provided by investors, including our management team, cash from the IPO and Private Placement, cash from the issuance of preferred units, and cash flows from operations and divestitures. While we expect to have continued access to our revolving credit facility, continued access could be adversely affected by current and future economic and business conditions that could result into reductions of the borrowing base. To date, our primary use of capital has been for the acquisition of oil and gas properties to increase our acreage position, as well as development and exploration of oil and gas properties. Our borrowings, net of unamortized debt issuance costs, were approximately $1,555.8 million and $1,417.7 million at December 31, 2019, and 2018, respectively. We also have other contractual commitments, which are described in *Note 14 — Commitments and Contingencies* in Part II, Item 8 of this Annual Report.

We may from time to time seek to retire or purchase our outstanding notes through cash purchases and/or exchanges (including for equity securities), in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 50% to 70% of our projected oil and natural gas production over a one to two year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our revolving credit facility to execute our current capital program, excluding any acquisitions we may consummate, make our interest payments on the 2024 Senior Notes, 2026 Senior Notes and credit facility and pay dividends on the Elevation Preferred Units.

If cash flow from operations does not meet our expectations which could be negatively effected by items outside of our control, in particular, macroeconomic conditions, we may reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our revolving credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves. In addition to reducing our capital spend, we may need to cut back on operating costs and other items within our control to maintain appropriate liquidity. We make no assurance that the measures we might take will be sufficient to provide the necessary liquidity.

Our 2020 capital budget for the drilling and completion of operated and non-operated wells is approximately $425 million to $475 million, substantially all of which we intend to allocate to the Core DJ Basin. We expect to drill 86 gross operated wells, complete 86 gross operated wells and turn-in-line 92 gross operated wells. Our capital budget anticipates a one to two operated rig drilling program and excludes up to $50 million for Elevation, a portion of which will be funded by Extraction, and any amounts that may be paid for potential acquisitions.

We had a Stock Repurchase Program in place during the years ended December 31, 2019 and 2018. Spending under this program was $137.0 million and $26.2 million and we repurchased 34.1 million and 4.1 million shares during the years ended December 31, 2019 and 2018, respectively. We also have a Senior Notes Repurchase Program. Spending under this program during the year ended December 31, 2019 was $39.3 million. We are authorized to repurchase up to a total of $100.0 million of our Senior Notes.

Cash Flows

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

	For the Year Ended December 31,	
	2019	2018
Net cash provided by operating activities	$ 557,957	$ 684,933
Net cash used in investing activities	(850,153)	(897,305)
Net cash provided by financing activities	89,592	440,590

Year Ended December 31, 2019 Compared to the Year Ended December 31, 2018

Net cash provided by operating activities. For the year ended December 31, 2019 as compared to the year ended December 31, 2018, our net cash provided by operating activities decreased by $127.0 million, primarily due to a decrease in operating revenues net of expenses of $163.5 million as a result of a decrease in commodity prices along with a decrease of $144.5 million related to changes in working capital. These decreases in net cash provided by operating activities were partially offset by a $153.8 million decrease in commodity derivative settlement payments and a decrease in general and administrative expenses paid in cash of $11.4 million.

Net cash used in investing activities. For the year ended December 31, 2019 as compared to the year ended December 31, 2018, our net cash used in investing activities decreased by $47.2 million primarily due to decreased spending of $322.5 million on oil and gas property additions partially offset by increased spending of $121.1 million on our gathering systems and facilities and increased spending of $23.1 million on other property and equipment. During 2019, there was a decrease in the cash received of $24.6 million from the sale of property and equipment and a $24.0 million increase in spending on our investment in unconsolidated subsidiaries. Additionally, we received $82.6 million less in proceeds from the sale of an unconsolidated subsidiary for the year ended December 31, 2019.

Net cash provided by financing activities. For the year ended December 31, 2019 as compared to the year ended December 31, 2018, our net cash provided by financing activities decreased by $351.0 million as a result of a decrease of $739.7 million from the issuance of the 2026 Senior Notes in 2018, partially offset by an increase from redemption of the 2021 Senior Notes for $585.6 million in 2018, including a make-whole premium of $35.6 million. Net borrowings on the revolver decreased $10.0 million and the cash received in 2019 from the issuance of Elevation Preferred Units was $49.5 million less than the cash received during 2018. Additionally, there was an increase in cash spent to repurchase common stock of $107.1 million, as result of our Share Repurchase Program, and senior notes of $39.3 million, as a result of our Senior Note Repurchase Program during the year ended December 31, 2019.

Working Capital

Our working capital deficit at December 31, 2019 was $240.8 million and working capital surplus at December 31, 2018 was $62.2 million. Our cash balances totaled $32.4 million and $235.0 million at December 31, 2019 and 2018, respectively.

Due to the amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our revolving credit facility will be sufficient to fund our working capital needs. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil, natural gas and NGL production will be the largest variables affecting our working capital.

Debt Arrangements

Our revolving credit facility has a maximum credit amount of $1.5 billion, subject to a borrowing base of $950.0 million and subject to the current maximum lending commitments of $950.0 million. All of our current and future subsidiaries are or will be guarantors under such facility, with the exception of Elevation. Amounts repaid under our revolving credit facility may be re-borrowed from time to time, subject to the terms of the facility. For more information on the revolving credit facility, please see *Note 6 — Long-Term Debt* in Part II, Item 8 of this Annual Report. The revolving credit facility is secured by liens on substantially all of our properties.

In July 2016, we closed a private offering of our 2021 Senior Notes that resulted in net proceeds of approximately $537.2 million. Our 2021 Senior Notes bore interest at an annual rate of 7.875%. Interest on our 2021 Senior Notes was payable on January 15 and July 15 of each year, and the first interest payment was made on January 15, 2017. Our 2021 Senior Notes would have matured on July 15, 2021. Our 2021 Senior Notes were guaranteed by all of our current and future restricted subsidiaries (other than Extraction Finance Corp., the co-issuer of our 2021 Senior Notes). In the first quarter of 2018, we closed a tender offer for the 2021 Senior Notes and subsequently redeemed all remaining outstanding 2021 Senior Notes. No 2021 Senior Notes remain outstanding.

In August 2017, we closed a private offering of our unsecured 7.375% Senior Notes due 2024 that resulted in net proceeds of approximately $392.6 million. Our 2024 Senior Notes bear interest at an annual rate of 7.375% Interest on our 2024 Senior Notes is payable on May 15 and November 15 of each year commencing on November 15, 2017. Our 2024 Senior Notes will mature on May 15, 2024. Our 2024 Senior Notes are guaranteed by certain of our current and future restricted subsidiaries.

In January 2018, we closed a private offering of our 2026 Senior Notes that resulted in net proceeds of approximately $737.9 million. Our 2026 Senior Notes bear interest at an annual rate of 5.625%. Interest on our 2026 Senior Notes is payable on February 1 and August 1 of each year, and the first interest payment was made on August 1, 2018. Our 2026 Senior Notes will mature on February 1, 2026. Our 2026 Senior Notes are guaranteed by certain of our current subsidiaries and by certain future restricted subsidiaries that guarantee our indebtedness under a credit facility.

Senior Note Repurchase Program

In January 2019, our Board of Directors authorized a program to repurchase up to $100.0 million of our Senior Notes. Our Senior Notes Repurchase Program is subject to restrictions under our Credit Facility and does not obligate it to acquire any specific nominal amount of Senior Notes. During 2019, we repurchased 2026 Senior Notes with a nominal value of $49.8 million for $39.3 million in connection with the Senior Notes Repurchase Program.

Revolving Credit Facility

The amount available to be borrowed under our revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, and will depend on the volumes of our proved oil and gas reserves and estimated cash flows from these reserves and other information deemed relevant by the administrative agent under our revolving credit facility. As of December 31, 2019, the borrowing base was $950.0 million, subject to current elected commitments of $950.0 million, and we had $470.0 million of borrowings outstanding under our revolving credit facility. The undrawn balance is constrained by the Company's quantitative quarterly covenants under the credit facility, including the current ratio and ratio of consolidated debt less cash balances to its consolidated EBITDAX, at the next required quarterly compliance date.

The credit facility matures on the earlier of (a) August 16, 2022, (b) April 15, 2021, if (and only if) (i) the Series A Preferred Stock of the Company (the "Series A Preferred Stock") have not been converted into common equity or redeemed prior to April 15, 2021 (the Company can redeem at any time), and (ii) prior to April 15, 2021, the maturity date of the Series A Preferred Stock has not been extended to a date that is no earlier than six months after August 16, 2022 or (c) the earlier termination in whole of the commitments. No principal payments are generally required until the credit agreement matures or in the event that the borrowing base falls below the outstanding balance.

Interest will be payable quarterly for alternate base rate loans and at the end of the applicable interest period for Eurodollar loans. We have a choice of borrowing in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the product of: (a) the LIBOR rate, multiplied by (b) a fraction (expressed as a decimal), the numerator of which is the number one and the denominator of which is the number one minus the reserve percentages (expressed as a decimal) on such date at which the administrative agent under our revolving credit facility is required to maintain reserves on ‘Eurocurrency Liabilities’ as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of our borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the adjusted one-month LIBOR rate (as calculated above) plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized. As of December 31, 2019, we had $470.0 million of outstanding borrowings under our revolving credit facility which may be limited based on existing financial covenants. The undrawn balance may be constrained by our quantitative quarterly covenants under the credit facility, including the current ratio and ratio of consolidated debt less cash balances to our consolidated EBITDAX, at the next required quarterly compliance date. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

The revolving credit facility is secured by liens on substantially all of our properties and guarantees from us and our current and future subsidiaries, with the exception of Elevation. The revolving credit facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- make certain changes to our capital structure;
- make or declare dividends;
- hedge future production or interest rates;
- enter into transactions with our affiliates;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The revolving credit facility requires us to maintain the following financial ratios:

- a current ratio, which is the ratio of our and our restricted subsidiaries' consolidated current assets (includes unused commitments under our revolving credit facility and excludes derivative assets) to our restricted subsidiaries' consolidated current liabilities (excludes obligations under our revolving credit facility, the senior notes and certain derivative liabilities), of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- a net leverage ratio, which is the ratio of our (i) consolidated debt less cash balances to (ii) consolidated EBITDAX for the four fiscal quarter period most recently ended, not to exceed 4.0 to 1.0 as of the last day of such fiscal quarter.

As of December 31, 2019, we were in compliance with the covenants under the credit agreement and expect to maintain compliance with the credit agreement covenants during 2020 assuming we are able to execute on our results consistent with the fourth quarter of 2019. Our 2020 capital program remains focused on generating free cash flow with an emphasis on strengthening our liquidity and balance sheet as we work to pay down debt. However, factors including those outside of our control may prevent us from maintaining compliance with such covenants, including the net leverage ratio covenant, at future measurement dates in 2020 and beyond. Such factors may include commodity price declines, lack of liquidity in property and capital markets and our inability to execute on our business plan. If we are unable to remain in compliance with our financial and non-financial covenants, we intend to seek covenant relief at a scheduled redetermination date or at an interim date, as appropriate. However, no assurances can be given that we will be able to obtain such relief. If any such covenant violations are not waived by the lenders and we cannot comply with such covenants, we will be in default, the lenders under our credit agreement and the holders of our senior notes could declare all outstanding principal and interest to be due and payable, and the lenders under our credit agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings, all of which would have a material adverse effect on our business, financial condition, results of operations and cash flows.

2021 Senior Notes

In July 2016, we closed a private offering of our 2021 Senior Notes that resulted in net proceeds of approximately $537.2 million. Our 2021 Senior Notes bore interest at an annual rate of 7.875% and matured on July 15, 2021.

Concurrent with the 2026 Notes Offering, we commenced a cash tender offer to purchase any and all of our 2021 Senior Notes. On January 24, 2018 we received approximately $500.6 million aggregate principal amount of the 2021 Senior Notes which were validly tendered (and not validly withdrawn). As a result, on January 25, 2018 we made a cash payment of approximately $534.2 million, which included principal of approximately $500.6 million, a make-whole premium of approximately $32.6 million and accrued and unpaid interest of approximately $1.0 million.

On February 17, 2018, we redeemed the approximately $49.4 million aggregate principal amount of the 2021 Senior Notes that remained outstanding after the Tender Offer and made a cash payment of approximately $52.7 million to the remaining holders of the 2021 Senior Notes, which includes a make-whole premium of $3.0 million and accrued and unpaid interest of approximately $0.3 million.

2024 Senior Notes

In August 2017, we closed a private offering of our 2024 Senior Notes that resulted in net proceeds of approximately $392.6 million. Our 2024 Senior Notes bear interest at an annual rate of 7.375%. Interest on our 2024 Senior Notes is payable on May 15 and November 15 of each year, and the first interest payment was paid on November 15, 2017. Our 2024 Senior Notes will mature on May 15, 2024.

We may, at our option, redeem all or a portion of our 2024 Senior Notes at any time on or after May 15, 2020 at the redemption prices set forth in the indenture governing the 2024 Senior Notes. We are also entitled to redeem up to 35% of the aggregate principal amount of our 2024 Senior Notes before May 15, 2020, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 107.375% of the principal amount of our 2024 Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to May 15, 2020, we may redeem some or all of our 2024 Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium. If we experience certain kinds of changes of control, holders of our 2024 Senior Notes may have the right to require us to repurchase their 2024 Senior Notes at 101% of the principal amount of the 2024 Senior Notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our 2024 Senior Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. Our 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our current subsidiaries and by certain future restricted subsidiaries that guarantees our indebtedness under a credit facility. The 2024 Senior Notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of our future subsidiaries that do not guarantee the 2024 Senior Notes.

2026 Senior Notes

In January 2018, we closed a private offering of our 2026 Senior Notes that resulted in net proceeds of approximately $737.9 million. Our 2026 Senior Notes bear interest at an annual rate of 5.625%. Interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year, and the first interest payment was made on August 1, 2018. Our 2026 Senior Notes will mature on February 1, 2026. As of December 31, 2019, we have repurchased 2026 Senior Notes with a nominal value of $49.8 million for $39.3 million in connection with the Senior Notes Repurchase Program.

We may, at our option, redeem all or a portion of our 2026 Senior Notes at any time on or after February 1, 2021 at the redemption prices set forth in the indenture governing the 2026 Senior Notes. We are also entitled to redeem up to 35% of the aggregate principal amount of our 2026 Senior Notes before February 1, 2021, with an amount of cash not greater than the net proceeds that we raise in certain equity offerings at a redemption price equal to 105.625% of the principal amount of our 2026 Senior Notes being redeemed plus accrued and unpaid interest, if any, to the redemption date. In addition, prior to February 1, 2021, we may redeem some or all of our 2026 Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium. If we experience certain kinds of changes of control, holders of our 2026 Senior Notes may have the right to require us to repurchase their 2026 Senior Notes at 101% of the principal amount of the 2026 Senior Notes, plus accrued and unpaid interest, if any, to the date of purchase.

Our 2026 Senior Notes are our senior unsecured obligations and rank equally in right of payment with all of our other senior indebtedness and senior to any of our subordinated indebtedness. Our 2026 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of our current subsidiaries and by certain future restricted subsidiaries that guarantee our indebtedness under a credit facility. The 2026 Senior Notes are effectively subordinated to all of our secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of our future subsidiaries that do not guarantee the 2026 Senior Notes.

Series A Preferred Stock

The holders of our Series A Preferred Stock (the "Series A Preferred Stock") are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). We elected to begin paying the dividend in kind commencing with the fourth quarter of 2019. The Series A Preferred Stock was convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Until the three-year anniversary of the closing of the IPO, we had the option to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock traded at or above a certain premium to our initial offering price, such premium was to decrease with time. On October 15, 2019, the three year anniversary passed for our ability to convert the Series A Preferred Stock into our common stock. We can now redeem the Series A Preferred Stock at any time for the liquidation preference, which is $189.9 million. The holder can convert to common stock through maturity on October 15, 2021. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash from funds legally available for such purpose in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Company and, in certain circumstances, the Series A Preferred Stock holders have options to redeem the Series A Preferred Stock. Our option to convert the Series A Preferred Stock into common stock expired in October 2019. The Series A Preferred Stock matures on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference.

Elevation Preferred Units

On July 3, 2018, Elevation entered into the Securities Purchase Agreement with the Purchaser, pursuant to which Elevation agreed to sell 150,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $150.0 million, in a transaction exempt from the registration requirements under the Securities Act. The Private Placement closed on July 3, 2018 and resulted in net proceeds of approximately $141.9 million, $25.4 million of which was a reimbursement for previously incurred midstream capital expenditures and general and administrative expenses. These Elevation Preferred Units represent the noncontrolling interest presented on the consolidated statement of changes in stockholders' equity. Elevation is a separate entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As of December 31, 2019 and 2018, respectively, $10.7 million and $136.9 million of cash was held by Elevation and is earmarked for construction of pipeline infrastructure to serve the development of acreage in its Hawkeye and Southwest Wattenberg areas.

In November 2018, we entered into the Elevation Gathering Agreements. Under the agreements, we agreed to drill 100 wells in Broomfield and 325 wells in Hawkeye by December 31, 2023 if both facilities are to be built. By way of comparison, Extraction drilled a total of 107 gross wells during the year ended December 31, 2019 and expects to drill 86 gross wells during the year ended December 31, 2020. However, not all of the wells expected to be drilled in 2020 will qualify as wells satisfying our commitments to Elevation. If we fail to complete the wells by the commitment deadline, then it would be deemed to be in breach of the agreement and Elevation could (at Elevation's discretion) be entitled to make a claim for damages against us and our affiliates. The Elevation Gathering Agreements were amended in April 2019 to provide for, among other amendments, the inclusion of additional gathering facilities in Elevation’s Badger facility. Pursuant to this amendment, if these additional gathering facilities are not completed by April 1, 2020, then within 30 days of such date we could (at Elevation's discretion) be required to make a payment to Elevation in the amount of 135% of all cost incurred by Elevation as of such date for the development and construction of such additional gathering facilities. We do not expect to complete these additional gathering facilities by such date. As of December 31, 2019, the costs incurred by Elevation for these additional gathering facilities totaled $33.9 million. We continue to work with Elevation’s financing partner in constructive discussions surrounding this target completion date. In December 2019, the Elevation Gathering Agreements were further amended such to provide Elevation additional connection fees that are consistent with market terms (the "Connect Fees"). In the fourth quarter of 2019, we incurred $19.5 million for Connect Fees pursuant to the Elevation Gathering Agreements, and we do not expect to incur more than the $23.5 million already paid during 2020 for the year ending December 31, 2020.

On July 10, 2019, Elevation closed on an additional 100,000 Elevation Preferred Units under an existing securities purchase agreement with a third party, pursuant to which Elevation had agreed to sell an additional 100,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $100.0 million, and resulting in net proceeds of approximately $96.5 million, after deducting discounts and related offering expenses.

The Elevation Preferred Units will entitle the Purchaser to receive quarterly dividends at a rate of 8.0% per annum (the "Dividend"). In respect of quarters ending prior to and including June 30, 2020, the Dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, the Dividend is payable solely in cash.

Commitments, Contingencies and Contractual Obligations

A summary of our commitments, contingencies and contractual obligations as of December 31, 2019 is provided in the following table (in thousands).

	Payments due by Period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Contractual Obligations					
Office leases(1)	$ 29,178	$ 3,337	$ 6,711	$ 6,877	$ 12,253
Drilling rig obligations(2)	13,306	12,018	1,288	—	—
Volume commitments(3)	1,141,223	157,697	362,466	337,942	283,118
Revolving credit facility and interest payable(4)	523,762	19,846	503,916	—	—
Senior Notes and Interest Payable(5)	1,488,946	88,984	137,771	519,334	742,857
Total	$ 3,196,415	$ 281,882	$ 1,012,152	$ 864,153	$ 1,038,228

(1) We lease two office spaces in Denver, Colorado and one office space in Houston, Texas under separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2028. The Houston, Texas lease expires on January 31, 2022. Total rental commitments under non-cancelable leases for office space were $29.2 million at December 31, 2019.

(2) As of December 31, 2019, we were subject to commitments on two drilling rigs under contracts that are set to expire on May 29, 2020 and February 25, 2021.

(3) Please refer to Delivery Commitments in *Note 14—Commitments and Contingencies* in Part II, Item 8 of this Annual Report.

(4) Calculated based on balance of $470.0 million outstanding borrowings under our revolving credit facility as of December 31, 2019 and assumes no borrowings until the maturity date of the facility. Interest on our revolving credit facility is payable at one of the following two variable rates as selected by us: a base rate based on the Prime Rate or the Eurodollar rate based in LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the Pricing Grid. Additionally, our revolving credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage.

(5) Calculated based on the December 31, 2019 outstanding aggregate principal amount on our 2024 Senior Notes of $400 million outstanding, at a fixed rate of 7.375%, and outstanding principal amount on our 2026 Senior Notes of $700.2 million outstanding, at a fixed rate of 5.625%. Interest is payable on our 2024 Senior Notes and 2026 Senior Notes on a semi-annual basis through the maturity dates of May 15, 2024 and February 1, 2026, respectively.

The above contractual obligations schedule does not include the Series A Preferred Stock or Elevation paid-in-kind commitment fee and dividend, future anticipated settlement of derivative contracts or estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties, as we cannot determine with accuracy the timing of such payments. Additionally, the above contractual obligations schedule does not include lease operating expenses or budgeted capital expenditures. For further discussion regarding our Series A Preferred Stock, Elevation Preferred Units, derivative contracts and estimated future costs associated with the abandonment of our oil and gas properties, please refer to *Note 10 — Equity, Note 7 — Commodity Derivative Instruments* and *Note 8 — Asset Retirement Obligations* in Part II, Item 8 of this Annual Report for the years ended December 31, 2019 and 2018. Additionally, the above contractual obligations schedule does not include $23.5 million of connect fees that we owe under the Elevation Gathering Agreements or the 135% of certain costs incurred by Elevation that we could (at Elevation's discretion) owe under the Elevation Gathering Agreements if certain additional gathering facilities in Elevation's Badger facility are not completed by April 1, 2020. Additionally, for further information regarding our contractual obligations, lease operating expenses and budgeted capital expenditures as of December 31, 2019, please refer to *Note 14 — Commitments and Contingencies* in Part II, Item 8 of this Annual Report, *"Historical Results of Operations and Operating Expenses"* for the year ended December 31, 2019 and 2018 and *"Capital Expenditures"* in Part II, Item 7 of this Annual Report.

As is customary in the oil and gas industry, we may at times have commitments in place to reserve or earn certain acreage positions or wells. If we do not meet such commitments, the acreage positions or wells may be lost or we may be required to pay damages if certain performance conditions are not met.

Off-Balance Sheet Arrangements

As of December 31, 2019, we do not have material off-balance sheet arrangements.

Impact of Inflation/Deflation and Pricing

All of our transactions are denominated in U.S. dollars. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, as prices for oil and natural gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to decline commodity prices. Historically, field-level prices received for our oil and natural gas production have been volatile. During the year ended December 31, 2019, commodity prices decreased during the first quarter, subsequently increased in the second quarter, and subsequently decreased in the third quarter and fourth quarter, while during the years ended December 31, 2018 and 2017, commodity prices generally increased. Changes in commodity prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel.

Critical Accounting Policies and Estimates

Use of Estimates in the Preparation of Financial Statements

The preparation of the financial statements in conformity with GAAP 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in impairment testing of oil and gas properties and goodwill; (3) depreciation, depletion, amortization and accretion; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations, including the determination of any resulting goodwill; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; (9) valuation of stock-based payments, and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. We evaluate our estimates on an on-going basis and base our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, we believe our estimates are reasonable.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

We capitalize interest, if debt is outstanding, during drilling operations in our exploration and development activities.

Oil and Gas Reserves

Our estimates of proved reserves are based on the quantities of oil, natural gas and NGL, 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 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. Our independent petroleum engineers, Ryder Scott, prepare a reserve and economic evaluation of all of our properties on a well-by-well basis. The accuracy of reserve estimates is a function of the:

- quality and quantity of available data;
- interpretation of that data;
- accuracy of various mandated economic assumptions; and
- judgment of the independent reserve engineer.

One of the most significant estimates we make is the estimate of oil, natural gas and NGL reserves. Oil, natural gas and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs and these estimates are inherently uncertain. For example, if estimates of proved reserves decline, our DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of oil and gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings. We cannot predict what reserve revisions may be required in future periods.

Ryder Scott estimated all of our proved reserve quantities as of December 31, 2019 and 2018. In connection with Ryder Scott performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests.

The following table presents information about proved reserve changes from period to period due to items we do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Year Ended December 31,	
	2019	**2018**
Revisions resulting from price changes (MBOE)	(18,049)	11,082
Revisions resulting from production, performance and other (MBOE)	(72,488)	(14,407)
Total revisions (MBOE)	(90,537)	(3,325)

The recent significant decline in oil, natural gas and NGL prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. We are unable to predict future commodity prices with any greater precision than the futures market. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes to our development plans or costs.

Depreciation, Depletion, Amortization and Accretion.

Our DD&A rate is dependent upon our estimates of total proved and proved developed reserves, which incorporate various assumptions and future projections. If our estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, which in turn reduces our net income. Such a decline in reserves may result from lower commodity prices or other changes to reserve estimates, as discussed above, and we are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploration and development program, as well as future economic conditions.

Impairment of Proved Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and gas properties and compares these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, estimated future operating costs, and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of long lived assets and goodwill in the consolidated statements of operations, which increases accumulated depletion, depreciation and amortization.

Future commodity pricing for oil is based on five-year West Texas Intermediate strip prices, which increased 7.2% from an average of $50.04/Bbl at December 31, 2018 to an average of $53.65/Bbl at December 31, 2019. Future commodity pricing for natural gas is based on five-year Henry Hub strip prices, which decreased 11% from an average of $2.70/MMBtu at December 31, 2018 to an average of $2.42/MMBtu at December 31, 2019. Future commodity pricing for NGLs is based on five-year WTI strip prices, which decreased 18% from an average of $19.73/Bbl at December 31, 2018 to an average of $14.95/Bbl at December 31, 2019.

Our impairment analyses requires us to apply judgment in identifying impairment indicators and estimating future cash flows of our oil and gas properties. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to an impairment charge.

For the year ended December 31, 2019, our impairment expense was $1.3 billion. We recognized $14.5 million related to impairment of the proved oil and gas properties in our northern field and $1.3 billion related to assets in one of our Core DJ Basin fields as the field's fair values did not exceed the carrying amounts associated with our proved oil and gas properties. For the year ended December 31, 2018, our impairment expense was $16.2 million related to impairment of the proved oil and gas properties in our northern field as the fair value did not exceed the carrying amount associated with our proved oil and gas properties in our northern field. No impairment expense was recognized for the year ended December 31, 2018 on proved oil and gas properties in our Core DJ Basin fields.

Forward commodity prices and estimates of future production play a significant role in determining impairment of proved oil and gas properties. As a result of lower commodity prices and their impact on our estimated future cash flows, we will continue to review our proved oil and gas properties for impairment. After our fourth quarter 2019 impairment charges in two of our Core DJ Basin fields at December 31, 2019, the carrying value of our oil and gas properties exceeded our expected undiscounted future cash flows for proved and risk-adjusted probable and possible reserves by approximately $33.8 million and $1.2 billion, respectively. Based on our discounted future cash flows as of December 31, 2019, a 10% decrease in NYMEX strip pricing, could cause us to recognize additional impairment expense on proved oil and gas properties related to assets in one of our Core DJ Basin fields of up to $330 million. At December 31, 2018, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by approximately $0.8 billion, or 30%. At December 31, 2017, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by approximately $1.6 billion or 68%.

Impairment of Unproved Oil and Gas Properties

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. We evaluate significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration and abandonment expenses in the consolidated statements of operations. As a result of the abandonment and impairment of unproved properties, we recognized $73.7 million and $25.7 million in abandonment and impairment expense for the years ended December 31, 2019 and 2018, respectively. To the extent we do not elect to renew current leases, we expect further abandonment charges in 2020.

Goodwill and Other Intangible Assets

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated value of the net assets acquired in business combinations. The Company tests goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test is performed at the reporting unit level, which represents the Company's oil and gas operations in its Core DJ Basin field. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of the Company's common shares could change the estimates of the fair value of the reporting unit and could result in an impairment charge. The Company performed a quantitative assessment as of September 30, 2018, which concluded the fair value of the reporting unit was greater than its carrying amount. The Company identified triggering events as of December 31, 2018, due to the decrease in commodity pricing and the quoted market price of the Company's common shares compared to September 30, 2018. As such, the Company performed a quantitative assessment as of December 31, 2018, utilizing an income approach based on estimates of the expected discounted future cash flows of the reporting unit's oil and gas properties, which concluded the fair value of the reporting unit was not greater than its carrying amount. As a result, the Company recorded goodwill impairment of $54.2 million, the entirety of the balance, for the year ended December 31, 2018. As such, no test for goodwill impairment was necessary for the year ended December 31, 2019.

Costs relating to the acquisition of internal-use software licenses are capitalized when incurred and amortized over the estimated useful life of the license.

Commodity Derivative Instruments

We have entered into commodity derivative instruments, as described below. We have utilized swaps, put options, and call options to reduce the effect of price changes on a portion of our future oil and natural gas production. A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of our purchased put options have deferred premiums. For the deferred premium puts, we agree to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We combine swaps, purchased put options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of our use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit our ability to benefit from favorable price movements. We may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. We do not enter into derivative contracts for speculative purposes.

The commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity derivative assets. We have not designated any of the derivative contracts as fair value or cash flow hedges. Therefore, we do not apply hedge accounting to the commodity derivative instruments. Net gains and losses on commodity derivative instruments are recorded based on the changes in the fair values of the derivative instruments. Net gains and losses on commodity derivative instruments are recorded in the commodity derivative gain (loss) line on the statements of operations. Our cash flow is only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in our statements of cash flows.

Our valuation estimate takes into consideration the counterparties' credit worthiness, our credit worthiness, and the time value of money. The consideration of the factors result in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. Please see "—How We Evaluate Our Operations—Derivative Arrangements."

Accounting for Business Combinations

We account for all of our business combinations using the purchase method, which is the only method permitted under FASB ASC 805, *Business Combinations*, and involves the use of significant judgment. In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, we must prepare estimates. To estimate the fair values of these properties, we prepare estimates of gas, oil and NGL reserves. We estimate future prices to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, when a discounted cash flow model is used, the discounted future net cash flows of probable and possible reserves are reduced by additional risk factors. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Asset Retirement Obligations

Our asset retirement obligations ("ARO") consist of estimated future costs associated with the plugging and abandonment of oil, natural gas and NGL wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws, and applicable lease terms. The fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free discount rate to be used; and inflation rates. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas property.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGL are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. We recognize revenues from the sale of oil, natural gas and NGL using the sales method of accounting, whereby revenue is recorded based on our share of volume sold, regardless of whether we have taken our proportional share of volume produced. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. We receive payment one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A 10% change in our revenue accrual would have impacted total operating revenues by approximately $10.5 million and $9.1 million for the years ended December 31, 2019 and 2018, respectively.

Stock-Based Payments

We granted awards under the LTIP to certain directors, officers and employees, including stock options, restricted stock units, performance stock awards, performance stock units, performance cash awards and cash awards which therefore required us to recognize the expense in our financial statements.

All stock-based payments to employees are measured at fair value on the grant date and expensed over the relevant service period. The fair value of stock option awards is determined by using the Black-Scholes option pricing model. The fair value of the PSAs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. All stock-based payment expense is recognized using the straight-line method and is included within general and administrative expenses in the consolidated statements of operations and stock-based compensation in the consolidated statements of cash flows. Forfeitures are recorded as they occur. Please refer to *Note 12 — Stock-Based Compensation* for additional discussion on stock-based payments.

Income Taxes

We account for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by deferral and state taxing authorities.

We periodically assess whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, we consider all the available positive and negative evidence and makes certain assumptions. We consider, among other things, our deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. We believe it is more likely than not that the benefit from net operating loss carryforwards will not be fully realized. In recognition of this risk, we have provided a valuation allowance on the deferred tax assets.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. We do not currently have uncertain tax positions.

On December 22, 2017, United States legislation referred to as the TCJA was signed into law. Many of the provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes changes to the Internal Revenue Code of 1986 (as amended, the "Code"). The most significant change included in the TCJA is a reduction in the corporate federal income tax rate from 35% to 21% which was accounted for as of December 31, 2017. During the third quarter of 2018, we completed the accounting for the income tax effect of the TCJA's limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a $0.4 million reduction in deferred tax assets that had been recorded as a provisional amount as of December 31, 2017. There are no remaining provision amounts associated with the TCJA as of December 31, 2019 and 2018.

Recent Accounting Pronouncements

Please refer to Recent Accounting Pronouncements in *Note 2 — Basis of Presentation and Significant Accounting Policies* in Part II, Item 8 of this Annual Report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, natural gas and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGL has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil prices on our revenues, we periodically enter into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations.

The following tables present our net derivative positions related to crude oil and natural gas sales in effect as of December 31, 2019:

	For the Three Months Ended							
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020	March 31, 2021	June 30, 2021	September 30, 2021	December 31, 2021
NYMEX WTI Crude Swaps:								
Notional volume (Bbl)	400,000	300,000	1,100,000	1,400,000	1,350,000	1,050,000	750,000	750,000
Weighted average fixed price ($/Bbl)	$ 60.28	$ 60.00	$ 59.74	$ 59.70	$ 58.72	$ 58.33	$ 54.97	$ 54.97
NYMEX WTI Crude Purchased Puts:								
Notional volume (Bbl)	3,325,000	2,600,000	2,000,000	1,800,000	1,050,000	1,050,000	750,000	750,000
Weighted average purchased put price ($/Bbl)	$ 55.67	$ 54.46	$ 54.78	$ 54.75	$ 54.30	$ 54.30	$ 54.00	$ 54.00
NYMEX WTI Crude Sold Calls:								
Notional volume (Bbl)	3,325,000	2,600,000	2,000,000	1,800,000	1,050,000	1,050,000	750,000	750,000
Weighted average sold call price ($/Bbl)	$ 62.46	$ 62.00	$ 61.87	$ 61.52	$ 62.37	$ 62.37	$ 61.32	$ 61.32
NYMEX WTI Crude Sold Puts:								
Notional volume (Bbl)	3,300,000	2,900,000	3,000,000	3,050,000	2,400,000	2,100,000	1,500,000	1,500,000
Weighted average sold put price ($/Bbl)	$ 42.82	$ 42.52	$ 43.15	$ 43.15	$ 43.50	$ 43.43	$ 43.00	$ 43.00
NYMEX HH Natural Gas Swaps:								
Notional volume (MMBtu)	8,400,000	9,000,000	9,000,000	9,000,000	—	—	—	—
Weighted average fixed price ($/MMBtu)	$ 2.76	$ 2.75	$ 2.75	$ 2.75	—	—	—	—
NYMEX HH Natural Gas Purchased Puts:								
Notional volume (MMBtu)	600,000	—	—	—	—	—	—	—
Weighted average purchased put price ($/MMBtu)	$ 2.90	—	—	—	—	—	—	—
NYMEX HH Natural Gas Sold Calls:								
Notional volume (MMBtu)	600,000	—	—	—	—	—	—	—
Weighted average sold call price ($/MMBtu)	$ 3.48	—	—	—	—	—	—	—
CIG Basis Gas Swaps:								
Notional volume (MMBtu)	11,400,000	11,400,000	11,400,000	11,400,000	—	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.61)	$ (0.61)	$ (0.61)	$ (0.61)	—	—	—	—

	For the Three Months Ended							
	March 31, 2022	June 30, 2022	September 30, 2022	December 31, 2022	March 31, 2023	June 30, 2023	September 30, 2023	December 31, 2023
NYMEX WTI Crude Swaps:								
Notional volume (Bbl)	255,000	255,000	255,000	255,000	225,000	225,000	225,000	225,000
Weighted average fixed price ($/Bbl)	$ 54.84	$ 54.84	$ 54.84	$ 54.84	$ 54.87	$ 54.87	$ 54.87	$ 54.87
NYMEX WTI Crude Sold Puts:								
Notional volume (Bbl)	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
Weighted average sold put price ($/Bbl)	$ 43.00	$ 43.00	$ 43.00	$ 43.00	$ 43.00	$ 43.00	$ 43.00	$ 43.00

As of December 31, 2019, the fair market value of our oil derivative contracts was a net asset of $16.9 million. Based on our open oil derivative positions at December 31, 2019, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $95.8 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $83.1 million. As of December 31, 2019, the fair market value of our natural gas derivative contracts was a net asset of $11.8 million. Based upon our open commodity derivative positions at December 31, 2019, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $5.9 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas derivative asset by approximately $6.0 million. Please see "—Derivative Arrangements."

Counterparty and Customer Credit Risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds with major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, natural gas and NGL to various types of customers, including marketers. Credit is extended based on an evaluation of the customer’s financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside of our control, none of which can be predicted with certainty. For the year ended December 31, 2019, we had certain major customers that exceeded 10% of total oil, natural gas and NGL revenues. We do not believe the loss of any single purchaser would materially impact its operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At December 31, 2019, we had commodity derivative contracts with ten counterparties, all but one of whom are lenders under our credit agreement. We do not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. Additionally, we use master netting agreements to minimize credit-risk exposure. The creditworthiness of our counterparties is subject to periodic review. For the years ended December 31, 2019, 2018 and 2017, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contains credit-risk related contingent features.

Interest Rate Risk

At December 31, 2019, we had $470.0 million of variable-rate debt outstanding. The impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $4.7 million. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR if we have variable-rate debt outstanding in the future. See "—Liquidity and Capital Resources—Debt Arrangements."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXTRACTION OIL & GAS, INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Extraction Oil & Gas, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Extraction Oil & Gas, Inc. and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of operations, of changes in stockholders' equity and noncontrolling interest and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO because a material weakness in internal control over financial reporting existed as of that date related to determining the appropriate contract termination date and evaluating the potential accounting implications of changes in termination dates of contracts with customers.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2019 consolidated financial statements, and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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/ PricewaterhouseCoopers LLP

Denver, Colorado
March 12, 2020

We have served as the Company's auditor since 2014.

EXTRACTION OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2019	December 31, 2018
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 32,382	$ 234,986
Accounts receivable		
Trade	32,009	41,695
Oil, natural gas and NGL sales	105,103	91,225
Inventory, prepaid expenses and other	36,702	26,816
Commodity derivative asset	17,554	48,907
Assets held for sale	—	21,008
Total Current Assets	223,750	464,637
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	4,530,934	3,916,622
Unproved oil and gas properties	524,214	609,284
Wells in progress	149,733	144,323
Less: accumulated depletion, depreciation, amortization and impairment charges	(2,985,983)	(1,152,590)
Net oil and gas properties	2,218,898	3,517,639
Gathering systems and facilities, net of accumulated depreciation (Note 2)	315,777	114,469
Other property and equipment, net of accumulated depreciation (Note 2)	72,542	39,849
Net Property and Equipment	2,607,217	3,671,957
Non-Current Assets:		
Commodity derivative asset	13,229	8,432
Other non-current assets	82,761	21,001
Total Non-Current Assets	95,990	29,433
Total Assets	$ 2,926,957	$ 4,166,027
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 190,864	$ 186,218
Revenue payable	108,493	117,344
Production taxes payable	115,489	57,516
Commodity derivative liability	1,998	196
Accrued interest payable	20,625	22,249
Asset retirement obligations	27,058	15,729
Liabilities related to assets held for sale	—	3,146
Total Current Liabilities	464,527	402,398
Non-Current Liabilities:		
Credit facility	470,000	285,000
Senior Notes, net of unamortized debt issuance costs (Note 6)	1,085,777	1,132,659
Production taxes payable	98,740	115,607
Commodity derivative liability	108	—
Other non-current liabilities	54,579	8,072
Asset retirement obligations	68,850	54,062
Deferred tax liability	—	109,176
Total Non-Current Liabilities	1,778,054	1,704,576
Total Liabilities	2,242,581	2,106,974
Commitments and Contingencies—Note 14		
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized; 185,280 issued and outstanding	175,639	164,367
Stockholders' Equity:		
Common stock, $0.01 par value; 900,000,000 shares authorized; 137,657,922 and 171,666,485 issued and outstanding, respectively	1,336	1,678
Treasury stock, at cost, 38,859,078 and 4,543,262 shares, respectively	(170,138)	(32,737)
Additional paid-in capital	2,156,383	2,153,661
Accumulated deficit	(1,743,208)	(375,788)
Total Extraction Oil & Gas, Inc. Stockholders' Equity	244,373	1,746,814
Noncontrolling interest (Note 10)	264,364	147,872
Total Stockholders' Equity	508,737	1,894,686
Total Liabilities and Stockholders' Equity	$ 2,926,957	$ 4,166,027

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART
OF THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	For the Year Ended December 31,		
	2019	2018	2017
Revenues:			
Oil sales	$ 721,429	$ 840,687	$ 419,904
Natural gas sales	108,873	105,629	92,322
NGL sales	75,072	114,427	92,070
Gathering and compression	1,261	—	—
Total Revenues	906,635	1,060,743	604,296
Operating Expenses:			
Lease operating expenses	97,254	79,413	60,358
Midstream operating expenses	2,258	—	—
Transportation and gathering	53,140	39,411	50,948
Production taxes	68,182	90,345	51,367
Exploration and abandonment expenses	88,794	31,611	36,256
Depletion, depreciation, amortization and accretion	524,537	435,775	314,999
Impairment of long lived assets and goodwill	1,337,996	70,928	1,647
(Gain) loss on sale of property and equipment and assets of unconsolidated subsidiary	421	(136,834)	451
General and administrative expenses	98,845	134,604	110,167
Total Operating Expenses	2,271,427	745,253	626,193
Operating Income (Loss)	(1,364,792)	315,490	(21,897)
Other Income (Expense):			
Commodity derivatives loss	(37,107)	(8,554)	(36,332)
Interest expense	(79,232)	(123,330)	(51,889)
Other income	4,535	5,099	2,010
Total Other Expense	(111,804)	(126,785)	(86,211)
Income (Loss) Before Income Taxes	(1,476,596)	188,705	(108,108)
Income tax benefit (expense)	109,176	(66,850)	63,700
Net Income (Loss)	$ (1,367,420)	$ 121,855	$ (44,408)
Net income attributable to noncontrolling interest	19,992	7,287	—
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	(1,387,412)	114,568	(44,408)
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	(19,436)	(16,869)	(16,279)
Net Income (Loss) Available to Common Shareholders, Basic and Diluted	$ (1,406,848)	$ 97,699	$ (60,687)
Net Income (Loss) Per Common Share (Note 13)			
Basic and diluted	$ (9.29)	$ 0.56	$ (0.35)
Weighted Average Common Shares Outstanding			
Basic and diluted	151,481	174,748	171,910

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND NONCONTROLLING INTEREST
(In thousands)

	Common Stock		Treasury Stock					Noncontrolling Interest	
	Shares	Amount	Shares	Amount	Additional Paid in Capital	(Accumulated Deficit)	Extraction Oil & Gas, Inc. Stockholders' Equity	Amount	Total Stockholders' Equity
Balance at January 1, 2017	171,835	$ 1,718	—	$ —	$ 2,067,590	$ (453,235)	$ 1,616,073	$ —	$ 1,616,073
Common stock issuance costs	—	—	—	—	(319)	—	(319)	—	(319)
Stock-based compensation	—	—	—	—	65,607	—	65,607	—	65,607
Series A Preferred Stock dividends	—	—	—	—	(10,885)	—	(10,885)	—	(10,885)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(5,394)	—	(5,394)	—	(5,394)
Repurchase of common stock	—	—	165	(2,105)	—	—	(2,105)	—	(2,105)
Shares issued under or returned to LTIP, net of tax withholdings	225	—	—	—	(1,804)	—	(1,804)	—	(1,804)
Net loss	—	—	—	—	—	(44,408)	(44,408)	—	(44,408)
Balance at December 31, 2017	172,060	$ 1,718	165	$ (2,105)	$ 2,114,795	$ (497,643)	$ 1,616,765	$ —	$ 1,616,765
Preferred Units issued	—	—	—	—	—	—	—	148,500	148,500
Preferred Units issuance costs	—	—	—	—	—	—	—	(7,915)	(7,915)
Preferred Units commitment fees and dividends paid-in-kind	—	—	—	—	(7,287)	—	(7,287)	7,287	—
Stock-based compensation	2,794	—	—	—	68,349	—	68,349	—	68,349
Series A Preferred Stock dividends	—	—	—	—	(10,885)	—	(10,885)	—	(10,885)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(5,984)	—	(5,984)	—	(5,984)
Repurchase of common stock	—	(40)	4,378	(30,632)	—	—	(30,672)	—	(30,672)
Shares issued under or returned to LTIP, net of tax withholdings	1,356	—	—	—	(5,327)	—	(5,327)	—	(5,327)
Net income	—	—	—	—	—	121,855	121,855	—	121,855
Balance at December 31, 2018	176,210	$ 1,678	4,543	$ (32,737)	$ 2,153,661	$ (375,788)	$ 1,746,814	$ 147,872	$ 1,894,686
Preferred Units issued	—	—	—	—	—	—	—	99,000	99,000
Preferred Units issuance costs	—	—	—	—	—	—	—	(2,500)	(2,500)
Preferred Units commitment fees and dividends paid-in-kind	—	—	—	—	(19,992)	—	(19,992)	19,992	—
Stock-based compensation	—	—	—	—	44,001	—	44,001	—	44,001
Series A Preferred Stock dividends	—	—	—	—	(12,796)	—	(12,796)	—	(12,796)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(6,640)	—	(6,640)	—	(6,640)
Repurchase of common stock	—	(342)	34,316	(137,401)	—	—	(137,743)	—	(137,743)
Shares issued under or returned to LTIP, net of tax withholdings	307	—	—	—	(1,851)	—	(1,851)	—	(1,851)
Net loss	—	—	—	—	—	(1,367,420)	(1,367,420)	—	(1,367,420)
Balance at December 31, 2019	176,517	$ 1,336	38,859	$ (170,138)	$ 2,156,383	$ (1,743,208)	$ 244,373	$ 264,364	$ 508,737

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Year Ended December 31,		
	2019	2018	2017
Cash flows from operating activities:			
Net income (loss)	$ (1,367,420)	$ 121,855	$ (44,408)
Reconciliation of net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	524,537	435,775	314,999
Abandonment and impairment of unproved properties	73,729	25,704	15,808
Impairment of long lived assets and goodwill	1,337,996	70,928	1,647
(Gain) loss on sale of property and equipment	1,431	(53,222)	451
Gain on sale of assets of unconsolidated subsidiary	(1,010)	(83,612)	—
Gain on repurchase of 2026 Senior Notes	(10,486)	—	—
Amortization of debt issuance costs and debt discount	5,482	13,250	4,260
Non-cash lease expenses	11,146	—	—
Contract asset	24,700	—	—
Deferred rent	—	348	(294)
Loss on commodity derivatives	37,107	8,554	36,332
Settlements on commodity derivatives	(678)	(134,624)	(11,985)
Premiums paid on commodity derivatives	(2,852)	(22,749)	(475)
Earnings in unconsolidated subsidiaries	(2,285)	(2,862)	(415)
Distributions from unconsolidated subsidiary	3,200	1,684	415
Make-whole premium expense on 2021 Senior Notes	—	35,600	—
Deferred income tax expense (benefit)	(109,176)	66,850	(63,700)
Stock-based compensation	43,954	68,349	65,607
Changes in current assets and liabilities:			
Accounts receivable—trade	3,630	8,562	(22,634)
Accounts receivable—oil, natural gas and NGL sales	(12,996)	2,076	(59,235)
Inventory, prepaid expenses and other	(332)	(853)	(523)
Accounts payable and accrued liabilities	(5,753)	(6,835)	31,202
Revenue payable	(7,598)	66,276	17,643
Production taxes payable	40,957	79,106	32,252
Accrued interest payable	(1,624)	(1,558)	4,186
Asset retirement expenditures	(27,702)	(13,669)	(4,168)
Net cash provided by operating activities	557,957	684,933	316,965
Cash flows from investing activities:			
Oil and gas property additions	(635,853)	(958,399)	(1,370,787)
Acquired oil and gas properties	—	—	(17,225)
Sale of property and equipment	56,305	80,879	5,155
Gathering systems and facilities additions	(202,513)	(81,406)	(4,452)
Other property and equipment additions	(39,090)	(15,991)	(17,737)
Investment in unconsolidated subsidiaries	(30,012)	(6,000)	—
Distributions from unconsolidated subsidiary, return of capital	—	—	518
Sale of assets of unconsolidated subsidiary	1,010	83,612	—
Net cash used in investing activities	(850,153)	(897,305)	(1,404,528)
Cash flows from financing activities:			
Borrowings under credit facility	465,000	635,000	565,000
Repayments under credit facility	(280,000)	(440,000)	(475,000)
Proceeds from the issuance of Senior Notes	—	739,664	394,000
Repayments of 2021 Senior Notes	—	(550,000)	—
Make-whole premium paid on 2021 Senior Notes	—	(35,600)	—
Repurchase of 2026 Senior Notes	(39,325)	—	—
Repurchase of common stock	(137,743)	(30,672)	(2,105)
Payment of employee payroll withholding taxes	(1,851)	(5,327)	(1,804)
Dividends on Series A Preferred Stock	(10,885)	(10,885)	(10,401)
Debt and equity issuance costs	(2,104)	(3,175)	(6,295)
Proceeds from issuance of Preferred Units	99,000	148,500	—
Preferred Unit issuance costs	(2,500)	(6,915)	—
Net cash provided by financing activities	89,592	440,590	463,395
Increase (decrease) in cash, cash equivalents and restricted cash	(202,604)	228,218	(624,168)
Cash, cash equivalents and restricted cash at beginning of period	234,986	6,768	630,936
Cash, cash equivalents and restricted cash at end of the period	$ 32,382	$ 234,986	$ 6,768
Supplemental cash flow information:			
Property and equipment included in accounts payable and accrued liabilities	$ 118,152	$ 141,952	$ 151,571
Cash paid for interest	93,084	84,224	54,492
Issuance of promissory note to unconsolidated subsidiary	—	35,329	—
Extinguishment of promissory note in exchange for equity with unconsolidated subsidiary	—	(35,329)	—
Accretion of beneficial conversion feature	6,640	5,984	5,394
Increase in dividends payable	—	—	484
Non-cash contribution to unconsolidated subsidiary	—	—	8,738
Preferred Units commitment fees and dividends paid-in-kind	19,992	7,287	—
Series A Preferred Stock dividends paid-in-kind	4,632	—	—

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THESE CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business and Organization

Extraction Oil & Gas, Inc. (the "Company" or "Extraction") is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado, as well as the construction and support of midstream assets to gather and process crude oil and gas production. Extraction is a public company listed for trading on the NASDAQ Global Select Market under the symbol "XOG."

Elevation Midstream, LLC ("Elevation"), a Delaware limited liability company and an unrestricted subsidiary of the Company, is focused on the construction and operation of gathering systems and facilities to serve the development of acreage in the Company's Hawkeye and Southwest Wattenberg areas. Midstream assets of Elevation are represented as the gathering systems and facilities line item within the consolidated balance sheet.

Note 2—Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Company, including its subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States ("GAAP").

Use of Estimates in the Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with GAAP 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Significant areas requiring the use of assumptions, judgments and estimates include (1) oil and gas reserves; (2) cash flow estimates used in impairment testing of oil and gas properties and goodwill; (3) depreciation, depletion, amortization and accretion; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations, including the determination of any resulting goodwill; (6) accrued revenue and related receivables; (7) valuation of commodity derivative instruments; (8) accrued liabilities; (9) valuation of stock-based payments, and (10) income taxes. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable under the circumstances.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments that are readily convertible into cash and have original maturities of three months or less when purchased.

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. The Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. On an on-going basis, management reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company did not record any allowance for uncollectible receivables as of or for the years ended December 31, 2019 and 2018.

Credit Risk and Other Concentrations

The Company's cash and cash equivalents are exposed to concentrations of credit risk. The Company manages and controls this risk by investing these funds with major financial institutions. The Company often has balances in excess of the federally insured limits.

The Company sells oil, natural gas and NGL to various types of customers, including oil marketers, pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside the Company's control, none of which can be predicted with certainty. For the years ended December 31, 2019, 2018 and 2017, respectively, the Company had the following customers that exceeded 10% of total oil, natural gas and NGL revenues. The Company does not believe the loss of any single purchaser would materially impact its operating results because crude oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

	For the Year Ended December 31,		
	2019	2018	2017
Customer A	77 %	76 %	65 %
Customer B	— %	11 %	19 %
Customer C	— %	— %	11 %

At December 31, 2019, the Company had commodity derivative contracts with ten counterparties, all of whom are lenders under our credit agreement. The Company does not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are credit worthy financial institutions deemed by management as competent and competitive market-makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The credit worthiness of the Company's counterparties is subject to periodic review. For the years ended December 31, 2019, 2018 and 2017, the Company did not incur any losses with respect to counterparty contracts. None of the Company's existing derivative instrument contracts contains credit-risk related contingent features.

Inventory, Prepaid Expenses and Other

The Company records well equipment inventory at the lower of cost or net realizable value. Prepaid expenses are recorded at cost. Inventory, prepaid expenses and other are comprised of the following (in thousands):

	As of December 31,	
	2019	2018
Well equipment inventory	$ 20,960	$ 19,916
Prepaid expenses	5,793	6,900
Contractual asset under ASC 606	9,949	—
	$ 36,702	$ 26,816

Additionally, the Company recognized impairment expense on well equipment inventory in the amount of $0.1 million and $0.7 million for the years ended December 31, 2018 and 2017, respectively. No such impairment expense was recognized for the year ended December 31, 2019.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and depleted on a units-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively. For the years ended December 31, 2019, 2018 and 2017, the Company excluded $149.7 million, $144.3 million and $127.4 million, respectively, of capitalized costs from depletion related to wells in progress. For the years ended December 31, 2019, 2018 and 2017, the Company recorded depletion expense on capitalized oil and gas properties of $513.7 million, $426.8 million and $306.7 million, respectively.

The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed at each period end. Due to the capital-intensive nature and the geological characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability. As of December 31, 2019, the Company had no suspended well costs. As of December 31, 2018, the Company had $6.1 million of suspended well costs, all capitalized less than one year and included in wells in progress as of the balance sheet date. These exploratory well costs were pending further engineering evaluation and analysis to determine if economic quantities of oil and gas reserves would be discovered. The Company completed its evaluation in 2019 and moved all of these suspended well costs to proved oil and gas properties based on the determination of proved reserves.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense. The Company expensed $0.2 million, $0.4 million and $1.4 million of costs associated with exploratory geological and geophysical costs for the years ended December 31, 2019, 2018 and 2017, respectively.

The Company capitalizes interest, if debt is outstanding, during drilling operations in its exploration and development activities. For the years ended December 31, 2019, 2018 and 2017, the Company capitalized interest of approximately $7.2 million, $8.2 million and $11.1 million, respectively.

Net carrying values of retired, sold or abandoned properties that constitute less than a complete unit of depreciable property are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in income. Gains or losses from the disposal of complete units of depreciable property are recognized to earnings.

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.

Impairment of Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. For all of its fields, the Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, estimated future operating costs, and discount rates commensurate with the risk associated with realizing the projected cash flows. Impairment expense for proved oil and gas properties is reported in impairment of long lived assets and goodwill in the consolidated statements of operations, which increases accumulated depletion, depreciation and amortization. For the year ended December 31, 2019, the Company recognized $14.5 million related to impairment of the proved oil and gas properties in its northern field and $1.3 billion related to assets in its Core DJ Basin field as the field's fair values did not exceed the carrying amounts associated with its proved oil and gas properties. For the year ended December 31, 2018, the Company recognized $16.2 million related to impairment of the proved oil and gas properties in its northern field as the fair value did not exceed the carrying amount associated with its proved oil and gas properties in its northern field. No impairment expense was recognized for the year ended December 31, 2018 on proved oil and gas properties in the Company's Core DJ Basin field. For the year ended December 31, 2017, the Company recognized no impairment expense on proved oil and gas properties.

Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. The Company evaluates significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and lease extension payments for unproved properties is reported in exploration and abandonment expenses in the consolidated statements of operations. As a result of the abandonment and impairment of unproved properties, the Company recognized $73.7 million, $25.7 million and $15.8 million impairment expense for the years ended December 31, 2019, 2018 and 2017, respectively.

Other Property and Equipment

Other property and equipment consists of (i) compressors, compressor stations, central tank batteries and disposal well facilities used in Extraction's oil and gas operations, (ii) land, (iii) rights of ways, pipeline and engineering costs, (iv) office leasehold improvements, (v) the field office, and (vi) other property and equipment including office furniture and fixtures and computer hardware and software. Impairment expense for other property and equipment is reported in impairment of long lived assets and goodwill in the consolidated statements of operations. The Company recognized $0.4 million and $0.9 million in impairment expense related to midstream facilities for the years ended December 31, 2018 and 2017, respectively, which increased accumulated depreciation recognized in other property and equipment, net of accumulated depreciation. These impairment expenses were primarily the result of right-of-way options that were no longer in the Company's plans for developing midstream infrastructure. Impairment expense related to midstream facilities was less than $0.1 million for the year ended December 31, 2019. For relevant years, gain or loss on the sale of other property and equipment is reported in gain (loss) on sale of property and equipment and assets of unconsolidated subsidiary in the consolidated statements of operations. The Company recognized $0.5 million of loss on the sale of other property and equipment related to the disposal of an oil pipeline that was not yet placed into service in the first quarter of 2017. Other property and equipment is recorded at historical cost and depreciated using the straight-line method.

The estimated useful lives of those assets depreciated under the straight-line method are as follows:

Rental equipment	1-10 years
Office leasehold improvements	3-10 years
Field office	30 years
Other	3-5 years

Other property and equipment is comprised of the following (in thousands):

	As of December 31,	
	2019	2018
Rental equipment	$ 4,043	$ 4,043
Land	42,273	27,595
Right-of-ways and pipeline	8,008	8,008
Office leasehold improvements	7,009	7,231
Field office	18,317	—
Other	8,884	6,946
Less: accumulated depreciation and impairment	(15,992)	(13,974)
	$ 72,542	$ 39,849

Gathering Systems and Facilities

Gathering systems and facilities consist of midstream assets such as land, rights of way, pipelines, equipment and construction and engineering costs associated with the construction of pipeline infrastructure to serve the development of the Company's acreage in its Hawkeye and Southwest Wattenberg areas. As of December 31, 2018, approximately $112.3 million of gathering systems and facilities assets had not been placed into service and therefore were not being depreciated during the year ended December 31, 2018. The majority of these assets were placed into service during the year ended December 31, 2019.

Gathering systems and facilities is comprised of the following (in thousands):

	As of December 31,	
	2019	2018
Gathering systems and facilities	$ 314,906	$ 112,281
Land associated with gathering systems and facilities	2,188	2,188
Less: accumulated depreciation	(1,317)	—
	$ 315,777	$ 114,469

Gathering systems and facilities balances are evaluated for potential impairment when events or changes in circumstances indicate that their carrying amounts may not be recoverable from expected undiscounted cash flows from the use and eventual disposition of an asset. If the carrying amount of the asset is not expected to be recoverable from future undiscounted cash flows, an impairment may be recognized. Any impairment is measured as the excess of the carrying amount of the asset over its estimated fair value.

In assessing gathering systems and facilities assets for impairment, management evaluates changes in business and economic conditions and their implications for recoverability of the assets' carrying amounts. The measure of impairments to be recognized, if any, depends upon management's estimate of the asset's fair value, which may be determined based on the estimates of future net cash flows or values at which similar assets were transferred in the market in recent transactions, if such data is available. Gathering systems and facilities are recorded at historical cost and depreciated using the straight-line method over 30 years.

Equity Method Investments

Investments in entities for which the Company exercises significant influence, but not control, are accounted for under the equity method of accounting. The Company recorded $44.6 million and $15.5 million of such investments included in other non-current assets on the consolidated balance sheets as of December 31, 2019 and 2018, respectively. The Company recognized $2.3 million, $2.9 million and $0.4 million of net income from such investments, including the accretion of any basis difference between the carrying amount of the investment and the amount of underlying equity in net assets, included in other income on the consolidated statements of operations and equity in earnings of unconsolidated subsidiary, in which we have a minority ownership interest on the consolidated statements of cash flows for the years ended December 31, 2019, 2018 and 2017, respectively.

For the year ended December 31, 2019, a gain on sale of unconsolidated subsidiary of $1.0 million was recorded relating to Elevation's August 2018 Divestiture. In August 2018, Elevation received proceeds of $83.6 million and recognized a gain of $83.6 million for the year ended December 31, 2018, upon the sale of assets of DJ Holdings, LLC, a subsidiary of Discovery Midstream Partners, LP, of which Elevation held a 10% membership interest. The Company acquired its interest in exchange for the contribution of an acreage dedication, which is considered a nonfinancial asset.

Deferred Lease Incentives

All incentives received from landlords for office leasehold improvements are recorded as deferred lease incentives and amortized over the term of the respective lease on a straight-line basis as a reduction of rental expense.

Debt Issuance Costs

Debt issuance costs include origination, legal, engineering, and other fees incurred to issue the debt in connection with the Company's credit facility, 2024 Senior Notes and 2026 Senior Notes (collectively, the "Senior Notes"). Debt issuance costs related to the credit facility are included in other non-current assets on the consolidated balance sheets and amortized to interest expense on the consolidated statement of operations on a straight-line basis over the respective borrowing term. Debt issuance costs related to the Senior Notes are amortized to interest expense using the effective interest method over the term of the debt.

Commodity Derivative Instruments

The Company has entered into commodity derivative instruments to reduce the effect of price changes on a portion of the Company’s future oil and natural gas production. The commodity derivative instruments are measured at fair value and are included in the accompanying balance sheets as commodity derivative assets and commodity derivative liabilities. The Company has not designated any of the derivative contracts as fair value or cash flow hedges. Therefore, the Company does not apply hedge accounting to the commodity derivative instruments. Net gains and losses on commodity derivative instruments are recorded based on the changes in the fair values of the derivative instruments. Net gains and losses on commodity derivative instruments are recorded in the commodity derivatives loss line on the consolidated statements of operations. The Company's cash flow is only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in the Company’s consolidated statements of cash flows.

Any premiums paid on derivative contracts are capitalized as part of the derivative assets or derivative liabilities, as appropriate, at the time the premiums are paid. Premium payments are reflected in cash flows from operating activities in the Company's consolidated statements of cash flows. Over time, as the derivative contracts settle, the differences between the cash received and the premiums paid or fair value of contracts acquired are recognized in net gains or losses on commodity or interest rate derivative contracts, and the cash received is reflected in cash flows from operating activities in the Company's consolidated statements of cash flows.

The Company's valuation estimate takes into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. The consideration of these factors result in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. Please refer to *Note 7 — Commodity Derivative Instruments* for additional discussion on commodity derivative instruments.

Goodwill and Other Intangible Assets

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in business combinations. The Company tests goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test was performed at the reporting unit level, which represented the Company’s oil and gas operations in its Core DJ Basin field. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. Any sharp prolonged decreases in the prices of oil and natural gas, as well as continued declines in the quoted market price of the Company’s common shares, could change the estimates of the fair value of the reporting unit and could result in an impairment charge. The Company performed a quantitative assessment as of September 30, 2018, which concluded the fair value of the reporting unit was greater than its carrying amount. The Company identified triggering events as of December 31, 2018, due to the decrease in commodity pricing and the quoted market price of the Company's common shares compared to September 30, 2018. As such, the Company performed a quantitative assessment as of December 31, 2018, utilizing an income approach based on estimates of the expected discounted future cash flows of the reporting unit's oil and gas properties, which concluded the fair value of the reporting unit was not greater than its carrying amount. As a result, the Company recorded goodwill impairment of $54.2 million, the entirety of the balance, for the year ended December 31, 2018. As such, no test for goodwill impairment was necessary for the year ended December 31, 2019.

Costs relating to the acquisition of internal-use software licenses are capitalized when incurred and amortized over the estimated useful life of the license, which is typically one to three years. The Company recorded $2.2 million, $3.0 million and $2.3 million of capitalized internal-use software costs for the years ended December 31, 2019, 2018 and 2017, respectively, on the consolidated balance sheets within the other non-current assets line item. Accumulated amortization for the years ended December 31, 2019 and 2018 was $5.3 million and $3.1 million, respectively. The Company recognized $2.2 million, $2.1 million and $1.0 million of amortization expense for the years ended December 31, 2019, 2018 and 2017, respectively.

Fair Value of Financial Instruments

The Company’s financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company’s credit facility approximates fair value as it bears interest at variable rates over the term of the loan. The Company’s Senior Notes are recorded at cost and the fair value is disclosed in *Note 9 — Fair Value Measurements*. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Asset Retirement Obligation

The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time the Company makes the decision to complete the well or a well is acquired. For additional discussion on asset retirement obligations please refer to *Note 8 — Asset Retirement Obligations.*

Environmental Liabilities

The Company is subject to federal, state and local environmental laws and regulations. These laws regulate the release, disposal or discharge of materials into the environment or otherwise relating to environmental protection and may require the Company to remove or mitigate the environmental effects of the discharge, disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a non-capital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted values unless the timing of cash payments for the liability or component is fixed or determinable. Management has determined that no significant environmental liabilities existed as of December 31, 2019. Please refer to *Note 14 — Commitments and Contingencies* for additional discussion on environmental liabilities.

Revenue Recognition

Revenues from the sale of oil, natural gas and NGL are recognized when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured and evidenced by a contract. The Company recognizes revenues from the sale of oil, natural gas and NGL using the sales method of accounting, whereby revenue is recorded based on the Company’s share of volume sold, regardless of whether the Company has taken its proportional share of volume produced. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2019 and 2018, the Company had oil imbalances of 12.7 and 22.0 MBbl, respectively, which the Company intends to settle with the counterparty in crude oil barrels. There was no material imbalance at December 31, 2017.

On January 1, 2018, the Company adopted ASC 606 - Revenue from Contracts with Customers ("ASC 606"). See *Adoption of ASC 606* for more information regarding the adoption of this standard.

Stock-Based Payments

The Company has granted awards under the LTIP to certain directors, officers and employees, including stock options, restricted stock units, performance stock awards, performance stock units, performance cash awards and cash awards which therefore required the Company to recognize the expense in its financial statements.

All stock-based payments to directors, officers and employees are measured at fair value on the grant date and expensed over the relevant service period. The fair value of stock option awards is determined by using the Black-Scholes option pricing model. The fair value of the PSAs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. All stock-based payment expense is recognized using the straight-line method and is included within general and administrative expenses in the consolidated statements of operations and stock-based compensation in the consolidated statements of cash flows. Forfeitures are recorded as they occur. Please refer to *Note 12 — Stock-Based Compensation* for additional discussion on stock-based payments.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by deferral and state taxing authorities.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, the Company considers all the available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. We believe it is more likely than not that the benefit from net operating loss carryforwards will not be fully realized. In recognition of this risk, we have provided a valuation allowance on the deferred tax assets.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The Company does not currently have uncertain tax positions.

Earnings Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) available to common shareholders by the weighted-average number of shares outstanding during the period. Diluted EPS reflects the potential dilution of securities that could share in the earnings available to common shareholders of the Company. The Company uses the "if-converted" method to determine the potential dilutive effects of its Series A Preferred Stock, and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock units and stock option awards.

Segment Reporting

Beginning in the fourth quarter of 2018, the Company had two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Prior to the fourth quarter of 2018, the Company had a single operating segment. Revenues and operating expenses associated with the gathering systems and facilities operations are derived from intersegment transactions for services provided to our exploration, development and production operations as well as third parties. Capital expenditures associated with gathering systems and facilities are being incurred to develop midstream infrastructure to support the Company's development of its oil and gas leasehold along with third-party activity. The activity of the exploration and production segment and gathering systems and facilities segment are being monitored by our chief operating decision maker ("CODM"). Revenues associated with the exploration and production segment are derived from the sale of our oil and natural gas production, as well as the sale of NGL that are extracted from our natural gas during processing. Revenues and operating expenses associated with the gathering and facilities segment are derived from intersegment transactions for services provided to the Company's exploration, development and production operations by Elevation Midstream, LLC., an unrestricted subsidiary to the Company, as well as third parties. In October 2019, Elevation commenced moving crude oil, natural gas and water through their newly constructed Badger central gathering facility. This facility enables Extraction and will enable others to efficiently transport crude oil and natural gas production along with water used during the completion process. The use of this gathering facility allows for the elimination of oil or water storage on well pad site and reduces truck traffic, which minimizes the impact to the surrounding environment and communities. Intersegment transactions are eliminated upon consolidation, including revenues and operating expenses during the construction of and from gathering services provided by Elevation to the Company. The CODM considers Adjusted EBITDAX as the measure of segment performance under ASC 280, *Segment Reporting*. Accounting policies for each segment are the same as the accounting policies as described herein. For more information about Segments, see *Note 16 — Segment Information.*

All of the Company’s operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

Recent Accounting Pronouncements

The accounting standard-setting organizations frequently issue new or revised accounting rules. The Company regularly reviews new pronouncements to determine their impact, if any, on its consolidated financial statements and related disclosures.

In August 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2018-15, which aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software and hosting arrangements that include an internal-use software license. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company plans to adopt this standard by the effective date and believes adoption will have an immaterial impact to the consolidated financial statements and related disclosures.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments—Credit Losses. In May 2019, ASU No. 2016-13 was subsequently amended by ASU No. 2019-04, Codification Improvements to Topic 326, Financial Instruments—Credit Losses and ASU No. 2019-05, Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief. ASU No.

2016-13, as amended, affects trade receivables, financial assets and certain other instruments that are not measured at fair value through net income. This ASU will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost and is effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. ASU No. 2016-13 will be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company plans to adopt this standard by the effective date and believes adoption will have an immaterial impact to the consolidated financial statements and related disclosures as the Company does not have a history of material credit losses.

In August 2018, the FASB issued ASU No. 2018-13, which improves the disclosure requirements on fair value measurements. For public entities, the new guidance is effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company plans to adopt this standard by the effective date and believes adoption will have an immaterial impact to the consolidated financial statements and related disclosures.

In May 2017, the FASB issued ASU No. 2017-09, which provides clarification and reduces both (1) diversity in practice and (2) cost and complexity when applying the guidance in Topic 718 Compensation - Stock Compensation, to a change to the terms or conditions of a share-based payment award. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that reporting period. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures.

In February 2017, the FASB issued ASU No. 2017-05, which provided clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, including interim reporting periods within that fiscal year. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU No. 2017-01, which clarifies the definition of a business when evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company adopted this ASU on January 1, 2018 and the adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures; however, this standard may result in more transactions being accounted for as asset acquisitions rather than business combinations.

In November 2016, the FASB issued ASU No. 2016-18, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment was effective retrospectively for reporting periods beginning after December 15, 2017. The Company adopted this ASU on January 1, 2018 and the retrospective adoption had no impact for the periods presented on the Company’s consolidated statements of cash flows, results of operations or financial position in this Annual Report.

In August 2016, the FASB issued ASU No. 2016-15, which addresses eight specific cash flow issues, including presentation of debt prepayments or debt extinguishment costs, with the objective of reducing the existing diversity in practice. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company adopted this ASU on January 1, 2018, which requires current period make-whole premiums to be presented in financing activities in the statement of cash flows and prior period debt prepayment costs to be reclassified from operating activities to financing activities in the statement of cash flows; however, there was no impact to the total change in cash and cash equivalents from period to period.

In February 2016, the FASB issued ASU No. 2016-02, which requires lessee recognition on the balance sheet of a right of use asset and a lease liability, initially measured at the present value of the lease payments. It further requires recognition in the income statement of a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis. Under the new standard, certain lease agreements with terms over one year are classified as right-of-use assets and right-of-use liabilities, which gross up the balance sheet. Finally, it requires classification of all cash payments within operating activities in the statements of cash flows. It is effective for fiscal years commencing after December 15, 2018 and early adoption is permitted. The FASB subsequently issued ASU No. 2017-13, ASU No. 2018-01, ASU No. 2018-10 and ASU No. 2018-11, which provided additional implementation guidance. The Company adopted these lease accounting standards on January 1, 2019 using a modified retrospective transition approach, which applied the provisions of the new guidance at the effective date without adjusting the comparative periods presented. Upon adoption, the Company elected the package of practical expedients permitted under the transition guidance with the new standard, which among other things, requires no reassessment of whether existing contracts are or contain leases as well as no reassessment of lease classification for existing leases upon adoption. The Company also elected the optional practical expedient permitted under the transition guidance within the new standard related to land easements that allows it to carry forward its current accounting treatment for land easements on existing agreements. The Company made an accounting policy election to keep leases with an initial term of twelve months or less off of the consolidated balance sheets. Please refer to *Note 5 — Leases* for further information.

In May 2014, the FASB issued ASU No. 2014-09, which establishes a comprehensive new revenue recognition model, referred to as ASC 606 - Revenue from Contracts with Customers, designed to depict the transfer of goods or services to a customer in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. The ASU allows for the use of either the full or modified retrospective transition method. In August 2015, the FASB issued ASU No. 2015-14, which deferred ASU No. 2014-09 for one year, and was effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period. The FASB subsequently issued ASU No. 2016-08, ASU No. 2016-10, ASU No. 2016-11, ASU No. 2016-12, ASU No. 2016-20, ASU No. 2017-13, ASU No. 2017-14 and ASU No. 2019-20, which provided additional implementation guidance. Refer to *—Adoption of ASC 606* for more information.

Adoption of ASC 606

On January 1, 2018, the Company adopted ASC 606. The Company adopted ASC 606 using the modified retrospective method to apply the new standard to all new contracts entered into on or after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of 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.

Changes to sales of natural gas and NGL, as well as transportation and gathering expenses, are due to the conclusion that certain midstream processing entities are the Company's customers in natural gas processing and marketing agreements in accordance with the five-step process in ASC 606. This is a change from previous conclusions reached for these agreements utilizing the principal versus agent indicators under ASC 605 where the Company determined it was the principal, the midstream processor was the agent and the third-party end user was its customer. As a result, the Company modified its presentation of revenues and operating expenses for these agreements. Revenues related to these agreements are now presented on a net basis for proceeds expected to be received from the midstream processing entity. Revenues from the sale of oil, natural gas and NGL, where the Company is a non-operating interest partner, are considered in the scope of *ASC 808 - Collaborative Arrangements*. Therefore, ASC 606 did not change the presentation of these revenues.

Transportation and gathering expense related to other agreements incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities will continue to be presented as transportation and gathering expense.

Revenues from Contracts with Customers

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

Oil Sales

Under the Company's crude purchase and marketing contracts, the Company generally sells oil production at the wellhead and collects an agreed-upon index price, net of pricing differentials. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the wellhead at the net price received.

The Company utilizes the sales method to account for producer imbalances, which continues to be applicable under ASC 606. As of December 31, 2019, the Company had an oil imbalance of 12.7 MBbl, which the Company intends to settle with the counterparty in crude oil barrels.

Natural Gas and NGL Sales

Under the Company's natural gas processing contracts, the Company delivers natural gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGL and residue gas. In these scenarios, we evaluate whether we are the principal or the agent in the transaction, and the point at which control of the hydrocarbons transfer to the customer. For those contracts where the Company has concluded the midstream processing entity is the Company's agent and the third-party end user is its customer (generally the Company's fixed-fee gathering and processing agreements), the Company recognizes revenue on a gross basis, with transportation and gathering expense presented as an operating expense in the consolidated statements of operations. Alternatively, for those contracts where the Company has concluded the midstream processing entity is its customer and controls the hydrocarbons (generally the Company's percentage of proceeds gathering and processing agreements), the Company recognizes natural gas and NGL revenues based on the net amount of the proceeds received from the midstream processing company.

In certain natural gas processing agreements, the Company may elect to take its residue gas and/or NGL in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, the Company delivers product to the third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the purchaser. In this scenario, the Company recognizes revenue when the control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering and processing expense attributable to the gas processing contracts, as well as any transportation expense incurred to deliver the product to the purchaser, are presented as transportation and gathering expense in the consolidated statements of operations.

Performance Obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 exempting the Company from disclosure of the transaction price of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14(a), which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company records revenue on its oil, natural gas and NGL sales at the time production is delivered to the purchaser. However, settlement statements for certain oil, natural gas and NGL sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the customer and the net commodity price that will be received for the sale of these commodity products. The Company records the differences between the revenue estimated and the actual amounts received for product sales in the month that payment is received from the customer.

Contract Balances

The Company has a certain revenue contract with an initial term beginning on November 1, 2016 and continuing until October 31, 2020 after which the contract begins an automatic month-to-month renewal unless terminated by either party giving notice at least 180 days prior to the effective termination date but in no event can either party give such notice earlier than November 1, 2020. Based on the accounting treatment pursuant to ASC 606 - Revenue from Contracts with Customers, the contract term ends on April 30, 2021 because it may be terminated by either party with no penalty effective as of such date. The contract term impacts the amount of consideration that can be included in the transaction price. Generally, under the Company's various sales contracts, the Company invoices customers once its performance obligations have been satisfied, at which point payment is unconditional. For the year ended December 31, 2019, the Company allocated $24.7 million to a satisfied performance obligation recognized within oil sales under ASC 606. As of December 31, 2019, the Company estimated a performance obligation under ASC 606 of $38.2 million, of which $3.9 million is recorded in accounts payable and accrued liabilities and $34.3 million is recorded in other non-current liabilities. A corresponding asset was recorded in the amount of $13.5 million, of which $9.9 million is recorded in inventory, prepaid expenses and other and $3.6 million is recorded in other non-current assets. The asset will be amortized into revenue over the contractual term of the contract, and the liability will be relieved if a deficiency payment is made to the counterparty or when the Company's minimum volume commitments are fulfilled.

The following table presents the Company's revenues disaggregated by revenue source. Transportation and gathering costs in the following table are not all of the transportation and gathering expenses that the Company incurs, only the expenses that are netted against revenues pursuant to ASC 606.

	For the Year Ended December 31,		
	2019	2018	2017[(1)]
Revenues:			
Oil sales	$ 721,429	$ 840,687	$ 419,904
Natural gas sales	129,969	121,180	92,322
NGL sales	92,429	134,558	92,070
Gathering and compression	1,261	—	—
Transportation and gathering included in revenues	(38,453)	(35,682)	—
Total Revenues	$ 906,635	$ 1,060,743	$ 604,296

(1) Revenue during and for the year ended December 31, 2017 was accounted for under ASC 605, *Revenue Recognition*.

There are no other accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of December 31, 2019 and through the date of this filing that would have a material impact on the Company's consolidated financial statements and related disclosures.

Note 3—Oil and Gas Properties

The Company's oil and gas properties are entirely within the United States. The net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	As of December 31,	
	2019	2018
Proved oil and gas properties	$ 4,530,934	$ 3,916,622
Unproved oil and gas properties(1)	524,214	609,284
Wells in progress(2)	149,733	144,323
Total capitalized costs(3)	$ 5,204,881	$ 4,670,229
Accumulated depletion, depreciation, amortization and impairment charge(4)	(2,985,983)	(1,152,590)
Net capitalized costs	$ 2,218,898	$ 3,517,639

(1) Unproved oil and gas properties represent unevaluated costs the Company excludes from the amortization base until proved reserves are established or impairment is determined.
(2) Costs from wells in progress are excluded from the amortization base until production commences.
(3) Includes accumulated interest capitalized of $39.8 million and $32.6 million as of December 31, 2019 and 2018, respectively.
(4) For more information about proved oil and gas properties impairment, see *Note 2 — Basis of Presentation and Significant Accounting Policies.*

The following table presents information regarding the Company's net costs incurred in oil and gas property acquisition, exploration and development activities (in thousands):

	For the Year Ended December 31,	
	2019	2018
Property acquisition costs:		
Proved	$ 21,024	$ 46,052
Unproved	35,207	79,708
Exploration costs(1)	3,569	8,840
Development costs	588,974	776,528
Total	$ 648,773	$ 911,128
Total excluding asset retirement costs	$ 598,778	$ 902,241

(1) Exploration costs do not include impairment and abandonment costs of unproved properties, which are included in the line item exploration and abandonment expenses in the consolidated statements of operations.

Note 4—Acquisitions and Divestitures

February 2020 Divestiture

In February 2020, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $14.7 million, subject to customary purchase price adjustments. The Company continues to explore divestitures, as part of our ongoing initiative to divest of non-strategic assets.

December 2019 Divestiture

In December 2019, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $10.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the December 2019 Divestiture.

August 2019 Divestiture

In August 2019, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $22.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the August 2019 Divestiture.

March 2019 Divestiture

In March 2019, the Company completed the sale of its interests in approximately 5,000 net acres of leasehold and producing properties for aggregate sales proceeds of approximately $22.4 million. The effective date for the March 2019 Divestiture was July 1, 2018 with purchase price adjustments calculated as of the closing date of $5.9 million, resulting in net proceeds of $16.5 million. No gain or loss was recognized for the March 2019 Divestiture.

As of December 31, 2018, these assets were classified as held for sale. The following table presents the information related to the assets held for sale in the December 31, 2018 consolidated balance sheet (in thousands):

		December 31, 2018
Assets:		
Property and equipment		
Proved oil and gas properties, net	$	11,945
Unproved oil and gas properties		9,063
Total Assets Held for Sale	$	21,008
Liabilities:		
Revenue payable	$	1,737
Production taxes payable		1,409
Total Liabilities Held for Sale	$	3,146
Total Assets Held for Sale, Net	$	17,862

The assets held for sale as of December 31, 2018 do not qualify for discontinued operations as they do not represent a strategic shift that will have a major effect of the Company's operations or financial results.

December 2018 Divestitures

In December 2018, the Company completed various sales of its interests in approximately 31,200 net acres of leasehold and primarily non-producing properties, for aggregate sales proceeds of approximately $8.5 million, subject to customary purchase price adjustments, and recognized a loss of $6.1 million.

August 2018 Divestiture

In August 2018, Elevation received proceeds of $83.6 million and recognized a gain of $83.6 million for the year ended December 31, 2018, upon the sale of assets of DJ Holdings, LLC, a subsidiary of Discovery Midstream Partners, LP, of which Elevation held a 10% membership interest. The Company acquired its interest in exchange for the contribution of an acreage dedication, which is considered a nonfinancial asset.

April 2018 Divestitures

In April 2018, the Company completed various sales of its interests in approximately 15,100 net acres of leasehold and primarily non-producing properties for aggregate sales proceeds of approximately $72.3 million and recognized a gain of $59.3 million for the year ended December 31, 2018.

April 2018 Acquisition

In April 2018, the Company acquired an unaffiliated oil and gas company's interest in approximately 1,000 net acres of non-producing leasehold primarily located in Arapahoe County, Colorado (the "April 2018 Acquisition"). Upon closing the seller received approximately $9.4 million in cash. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

January 2018 Acquisition

On January 8, 2018, the Company acquired an unaffiliated oil and gas company's interest in approximately 1,200 net acres of non-producing leasehold located in Arapahoe County, Colorado, (the "January 2018 Acquisition"). Upon closing the seller received approximately $11.6 million in cash. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

November 2017 Acquisition

On November 15, 2017, the Company acquired an unaffiliated oil and gas company's interest in approximately 36,600 net acres of leasehold and primarily non-producing properties located in Arapahoe County, Colorado, (the "November 2017 Acquisition"). Upon closing the seller received $214.3 million in cash, subject to customary purchase price adjustments. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

July 2017 Acquisition

On July 7, 2017, the Company acquired an unaffiliated oil and gas company’s interests in approximately 12,500 net acres of leasehold and primarily non-producing properties located primarily in Adams County, Colorado, (the "July 2017 Acquisition"). Upon closing the seller received total consideration of $84.0 million in cash. The effective date for the July 2017 Acquisition is July 1, 2017. This transaction has been accounted for as an asset acquisition. The acquisition provided new development opportunities in the Core DJ Basin.

June 2017 Acquisition

On June 8, 2017, the Company acquired an unaffiliated oil and gas company’s interests in approximately 160 net acres of leasehold and related producing properties located in Weld County, Colorado (the "June 2017 Acquisition"). The Company paid approximately $13.4 million in cash consideration in connection with the closing of the June 2017 Acquisition. The effective date for the acquisition was January 1, 2017, with purchase price adjustments calculated as of the closing date of June 8, 2017. The acquisition increased the Company's interest in existing operated wells. The acquired producing properties contributed $3.3 million of revenue and $2.5 million of earnings, respectively, for the year ended December 31, 2018. The acquired producing properties contributed $3.7 million of revenue and $3.0 million of earnings, respectively, for the year ended December 31, 2017. No significant transaction costs related to the acquisition were incurred for the years ended December 31, 2019, 2018 and 2017.

The June 2017 Acquisition was accounted for using the acquisition method under ASC 805, *Business Combinations*, which required the acquired assets and liabilities to be recorded at fair value as of the acquisition date of June 8, 2017. In August 2017, the Company completed the transaction’s post-closing settlement. The following table summarizes the purchase price and the final allocation of the fair values of assets acquired and liabilities assumed (in thousands):

Purchase Price	**June 8, 2017**
Consideration given	
Cash	$ 13,395
Total consideration given	$ 13,395
Allocation of Purchase Price	
Proved oil and gas properties	$ 13,495
Total fair value of oil and gas properties acquired	13,495
Asset retirement obligations	(100)
Fair Value of Net Assets Acquired	$ 13,395

Pro forma financial information is not provided for the June 2017 Acquisition as all adjustments were determined to be insignificant.

Note 5—Leases

The Company accounts for leases in accordance with ASC 842, *Leases*, which it adopted on January 1, 2019, applying the modified retrospective transition approach as of the effective date of adoption (see *"Recent Accounting Pronouncements"* for impacts of adoption).

The Company enters into operating leases for certain drilling equipment, completions equipment, equipment ancillary to drilling and completions, office facilities, compressors and office equipment. Under ASC 842, a contract is or contains a lease when (i) the contract contains an explicitly or implicitly identified asset and (ii) the customer obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the contract in exchange for consideration. The Company assesses whether an arrangement is or contains a lease at inception of the contract. All leases (operating leases), other than those that qualify for the short-term recognition exemption, are recognized as of the lease commencement date on the balance sheet as a liability for its obligation related to the lease and a corresponding asset representing its right to use the underlying asset over the period of use.

The Company's leases have remaining terms up to nine years. Certain of our lease agreements contain options to extend or early terminate the agreement. The lease term used to calculate the lease asset and liability at commencement includes options to extend or terminate the lease when it is reasonably certain that we will exercise that option. When determining whether it is reasonably certain that the Company will exercise an option at commencement, it considers various economic factors, including capital expenditure strategies, the nature, length, and underlying terms of the agreement, as well as the uncertainty of the condition of leased equipment at the end of the lease term. Based on these determinations, the Company generally determines that the exercise of renewal options would not be reasonably certain in determining the expected lease term for leases, other than certain operating compressor leases.

The discount rate used to calculate the present value of the future minimum lease payments is the rate implicit in the lease, when readily determinable. As the Company's leases generally do not provide an implicit rate, the Company uses its incremental borrowing rate based on its revolving credit facility, which includes consideration of the nature, term, and geographic location of the leased asset.

Certain of the Company's leases include variable lease payments, including payments that depend on an index or rate, as well as variable payments for items such as property taxes, insurance, maintenance, and other operating expenses associated with leased assets. Payments that vary based on an index or rate are included in the measurement of the Company's lease assets and liabilities at the rate as of the commencement date. All other variable lease payments are excluded from the measurement of the Company's lease assets and liabilities and are recognized in the period in which the obligation for those payments is incurred. The Company's lease agreements do not contain any material residual value guarantees or material restrictive covenants.

The Company has elected, for all classes of underlying assets, to not apply the balance sheet recognition requirements of ASC 842 to leases with a term of one year or less, and instead, recognize the lease payments in the consolidated statements of operations on a straight-line basis over the lease term. The Company has also made the election, for its certain drilling equipment, completions equipment, equipment ancillary to drilling and completions, compressors and office equipment classes of underlying assets, to account for lease and non-lease components in a contract as a single lease component.

For the year ended December 31, 2019, lease costs, which represent the straight-line lease expense of right-of-use ("ROU") assets and short-term leases, were as follows (in thousands):

	For the Year Ended December 31, 2019
Lease Costs included in the Consolidated Balance Sheets	
Proved oil and gas properties, including drilling, completions and ancillary equipment, and gathering systems and facilities(1)	$ 259,737
Lease Costs included in the Consolidated Statements of Operations	
Operating lease costs(2)	$ 33,025
General and administrative expenses(3)	3,821
Total operating lease costs	$ 36,846
Total lease costs	$ 296,583

(1) Represents short-term lease capital expenditures related to drilling rigs, completions equipment and other equipment ancillary to the drilling and completion of wells.
(2) Includes $8.8 million of lease costs accounted for under ASC 842.
(3) Includes $1.4 million of lease costs accounted for under ASC 842.

Supplemental cash flow information related to operating leases for the year ended December 31, 2019, was as follows (in thousands):

	For the Year Ended December 31, 2019
Cash paid for amounts included in the measurements of lease liabilities	
Operating cash flows from operating leases	$ 12,923
Right-of-use assets obtained in exchange for lease obligations	
Operating leases	$ 12,805

Supplemental balance sheet information related to operating leases as of December 31, 2019, were as follows (in thousands, except lease term and discount rate):

	Classification	As of December 31, 2019
Operating Leases		
Operating lease right-of-use assets	Other non-current assets	$ 29,186
Operating lease obligation - short-term	Accounts payable and accrued liabilities	17,388
Operating lease obligation - long-term	Other non-current liabilities	17,166
Total operating lease liabilities		$ 34,554
Weighted Average Remaining Lease Term in Years		
Operating leases		4.4
Weighted Average Discount Rate		
Operating leases		4.2 %

As of December 31, 2019, the Company was subject to commitments on two drilling rig contracts one of which is contracted through February 2021. As of December 31, 2019, the Company had an insignificant amount of additional operating leases that have not yet commenced, of which none included involvement with the construction or design of the underlying asset.

Note 6—Long-Term Debt

As of the dates indicated in the table below, the Company's long-term debt consisted of the following (in thousands):

	As of December 31,	
	2019	2018
Credit facility due August 16, 2022 (or an earlier time as set forth in the credit facility)	$ 470,000	$ 285,000
2024 Senior Notes due May 15, 2024	400,000	400,000
2026 Senior Notes due February 1, 2026	700,189	750,000
Unamortized debt issuance costs on Senior Notes	(14,412)	(17,341)
Total long-term debt	1,555,777	1,417,659
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 1,555,777	$ 1,417,659

Credit Facility

In August 2017, the Company entered into an amendment and restatement of its existing credit facility (prior to amendment and restatement, the "Prior Credit Facility"), to provide aggregate commitments of $1.5 billion with a syndicate of banks, which is subject to a borrowing base. The credit facility matures on the earlier of (a) August 16, 2022, (b) April 15, 2021, if (and only if) (i) the Series A Preferred Stock of the Company (the "Series A Preferred Stock") have not been converted into common equity or redeemed prior to April 15, 2021 (the Company can redeem at any time), and (ii) prior to April 15, 2021, the maturity date of the Series A Preferred Stock has not been extended to a date that is no earlier than six months after August 16, 2022 or (c) the earlier termination in whole of the commitments. No principal payments are generally required until the credit agreement matures or in the event that the borrowing base falls below the outstanding balance.

In January 2018, the Company amended its revolving credit facility to (i) increase the borrowing base from $525.0 million to $750.0 million, subject to the current elected commitments of $650.0 million, (ii) increase the maximum amount for the letter of credit issued in favor of a purchaser of its crude oil from $25.0 million to $35.0 million, and (iii) amend certain provisions of the credit agreement, including the commitments and allocations of each lender. In connection with the 2026 Senior Notes Offering (as defined below), the borrowing base was automatically reduced to $700.0 million; however, the current elected commitments remained at $650.0 million.

In February 2018, the Company entered into a consent agreement and amended its revolving credit facility to (i) provide for consent by the lenders to (a) the designation of Elevation as an unrestricted subsidiary and (b) the transfer of certain assets by the Company and one of the guarantors to such unrestricted subsidiary; and (ii) amend certain provisions of the credit agreement, including the incurrence of indebtedness covenant to permit certain indebtedness in connection with certain transportation service agreements with such unrestricted subsidiary.

In May 2018, the Company amended its revolving credit facility to (i) increase the borrowing base from $700.0 million to $800.0 million, subject to current elected commitments of $650.0 million and (ii) reduce each of the applicable interest rate margins for borrowings by 0.50%.

In October 2018, the Company amended its revolving credit facility to (i) postpone the November 1, 2018 scheduled borrowing base redetermination until December 15, 2018 and (ii) permit the Company to make payments with respect to its own equity, subject to certain terms, conditions and financial thresholds.

In December 2018, the Company's revolving credit facility was redetermined to increase the borrowing base from $800.0 million to $1.2 billion, associated with the postponed November 1, 2018 scheduled borrowing base determination. The current elected commitments remained at $650.0 million.

In January 2019, the Company amended its revolving credit facility to permit prepayments and redemptions of its unsecured bonds, subject to certain terms, conditions and financial thresholds.

In June 2019, the Company amended its revolving credit facility to (i) increase the elected commitments from $650.0 million to $900.0 million, (ii) increase the amount for permitted letters of credit from $50.0 million to $100.0 million and increase in the letter of credit for the Company's oil marketer from $35.0 million to $40.0 million, (iii) decrease the borrowing base from $1.2 billion to $1.1 billion and (iv) increase the limitation on permitted investments from $15.0 million to $20.0 million.

In August 2019, the Company amended its revolving credit facility to increase the elected commitments from $900.0 million to $1.0 billion.

In November 2019, the Company's revolving credit facility was redetermined to decrease the borrowing base from $1.1 billion to $950.0 million, associated with the scheduled borrowing base redetermination. The current elected commitments were also decreased to $950.0 million.

As of December 31, 2019, the credit facility was subject to a borrowing base of $950.0 million, subject to current elected commitments of $950.0 million. As of December 31, 2019, the Company had $470.0 million of borrowings outstanding. As of December 31, 2018, the Company had $285.0 million outstanding borrowings. As of December 31, 2019 and 2018, the Company had standby letters of credit of $49.5 million and $35.7 million, respectively, which reduces the availability of the undrawn borrowing base. At December 31, 2019, the undrawn balance under the credit facility was $430.5 million after considering letters of credit and is constrained by the Company's quantitative quarterly covenants under the credit facility, including the current ratio and ratio of consolidated debt less cash balances to its consolidated EBITDAX. As of the date of this filing, the Company had $470.0 million borrowings outstanding under the credit facility.

The amount available to be borrowed under the Company's revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, and will depend on the volumes of the Company's proved oil and gas reserves, commodity prices, estimated cash flows from these reserves and other information deemed relevant by the administrative agent under the Company's revolving credit facility.

Interest on the credit facility is payable at one of the following two variable rates as selected by the Company: a base rate based on the Prime Rate or the Eurodollar rate, based on LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the pricing grid below. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The weighted average interest rate for the years ending December 31, 2019 and 2018 was 4.8% and 5.1%, respectively. The grid below shows the Base Rate Margin and Eurodollar Margin depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	Eurodollar Margin	Base Rate Margin	Commitment Fee Rate
Level 1	<25%	1.50 %	0.50 %	0.38 %
Level 2	≥ 25% < 50%	1.75 %	0.75 %	0.38 %
Level 3	≥ 50% < 75%	2.00 %	1.00 %	0.50 %
Level 4	≥ 75% < 90%	2.25 %	1.25 %	0.50 %
Level 5	≥90%	2.50 %	1.50 %	0.50 %

The credit facility contains representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on dividends, distributions, redemptions and restricted payments covenants; (iii) limitations on investments, loans and advances covenants; and (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants. Additionally, the credit facility limits the Company entering into hedges in excess of 85% of its anticipated production volumes.

The credit facility also contains financial covenants requiring the Company to comply on the last day of each quarter with a current ratio of its restricted subsidiaries' current assets (includes availability under the revolving credit facility and unrestricted cash and excludes derivative assets) to its restricted subsidiaries' current liabilities (excludes obligations under the revolving credit facility, senior notes and certain derivative liabilities), of not less than 1.0 to 1.0 and to maintain, on the last day of each quarter, a ratio of its restricted subsidiaries' debt less cash balances to its restricted subsidiaries EBITDAX (EBITDAX is defined as net income adjusted for interest expense, income tax expense/benefit, DD&A, exploration and abandonment expenses as well as certain non-recurring cash and non-cash charges and income (such as stock-based compensation expense, unrealized gains/losses on commodity derivatives and impairment of long-lived assets and goodwill), subject to pro forma adjustments for non-ordinary course acquisitions and divestitures) for the four fiscal quarter period most recently ended, of not greater than 4.0 to 1.0 as of the last day of such fiscal quarter. As of December 31, 2019, the Company was in compliance with the covenants under the credit agreement and expects to maintain compliance with the credit agreement covenants during 2020 assuming the Company is able to execute on the results consistent with the fourth quarter of 2019. The Company's 2020 capital program remains focused on generating free cash flow with an emphasis on strengthening liquidity and the balance sheet as the Company works to pay down debt. However, factors including those outside of the Company's control may prevent maintaining compliance with such covenants, including the net leverage ratio covenant, at future measurement dates in 2020 and beyond. Such factors may include commodity price declines, lack of liquidity in property and capital markets and the Company's inability to execute on its business plan. If the Company is unable to remain in compliance with financial and non-financial covenants, it intends to seek covenant relief at a scheduled redetermination date or at an interim date, as appropriate. However, no assurances can be given that the Company will be able to obtain such relief. If any such covenant violations are not waived by the lenders and the Company cannot comply with such covenants, the Company will be in default, the lenders under the credit agreement and the holders of the Company's senior notes could declare all outstanding principal and interest to be due and payable, and the lenders under the credit agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings.

Any borrowings under the credit facility are collateralized by substantially all of the assets of the Company and certain of its subsidiaries, including oil and gas properties, personal property and the equity interests of those subsidiaries of the Company. The Company has entered into oil and natural gas hedging transactions with several counterparties that are also lenders under the credit facility. The Company's obligations under these hedging contracts are secured by the collateral securing the credit facility. Elevation is a separate entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As of December 31, 2019, $10.7 million of cash was held by Elevation and is earmarked for construction of pipeline infrastructure to serve the development of acreage in its Hawkeye and Southwest Wattenberg areas.

2021 Senior Notes

In July 2016, the Company issued at par $550.0 million principal amount of 7.875% Senior Notes due July 15, 2021 (the "2021 Senior Notes" and the offering, the "2021 Senior Notes Offering"). The 2021 Senior Notes bore an annual interest rate of 7.875%. The interest on the 2021 Senior Notes was payable on January 15 and July 15 of each year commencing on January 15, 2017. The Company received net proceeds of approximately $537.2 million after deducting discounts and fees.

Concurrent with the 2026 Senior Notes Offering (as defined below), the Company commenced a cash tender offer to purchase any and all of its 2021 Senior Notes. On January 24, 2018, the Company received approximately $500.6 million aggregate principal amount of the 2021 Senior Notes which were validly tendered (and not validly withdrawn). As a result, on January 25, 2018 the Company made a cash payment of approximately $534.2 million, which includes principal of approximately $500.6 million, a make-whole premium of approximately $32.6 million and accrued and unpaid interest of approximately $1.0 million.

On February 17, 2018, the Company redeemed approximately $49.4 million aggregate principal amount of the 2021 Senior Notes that remained outstanding after the Tender Offer and made a cash payment of approximately $52.7 million to the remaining holders of the 2021 Senior Notes, which included a make-whole premium of $3.0 million and accrued and unpaid interest of approximately $0.3 million.

2024 Senior Notes

In August 2017, the Company issued at par $400.0 million principal amount of 7.375% Senior Notes due May 15, 2024 (the "2024 Senior Notes" and the offering, the "2024 Senior Notes Offering"). The 2024 Senior Notes bear an annual interest rate of 7.375%. The interest on the 2024 Senior Notes is payable on May 15 and November 15 of each year which commenced on November 15, 2017. The Company received net proceeds of approximately $392.6 million after deducting fees.

The Company's 2024 Senior Notes are its senior unsecured obligations and rank equally in right of payment with all of its other senior indebtedness and senior to any of its subordinated indebtedness. The Company's 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantees its indebtedness under a credit facility (the "2024 Senior Note Guarantors"). The 2024 Senior Notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under its revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of its future subsidiaries that do not guarantee the 2024 Senior Notes.

The 2024 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company’s or any of its Guarantors’ equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2024 Senior Notes (the "2024 Senior Notes Indenture") also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2024 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2024 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2024 Senior Notes may declare all outstanding 2024 Senior Notes to be due and payable immediately.

2026 Senior Notes

In January 2018, the Company issued at par $750.0 million principal amount of 5.625% Senior Notes due February 1, 2026 (the "2026 Senior Notes" and the offering, the "2026 Senior Notes Offering"). The 2026 Senior Notes bear an annual interest rate of 5.625%. The interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year commencing on August 1, 2018. The Company received net proceeds of approximately $737.9 million after deducting fees. The Company used $534.2 million of the net proceeds from the 2026 Senior Notes Offering to fund the tender offer for its 2021 Senior Notes, $52.7 million to redeem any 2021 Senior Notes not tendered and the remainder for general corporate purposes.

The Company's 2026 Senior Notes are the Company's senior unsecured obligations and rank equally in right of payment with all of the Company's other senior indebtedness and senior to any of the Company's subordinated indebtedness.

The Company's 2026 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantee the Company's indebtedness under a credit facility. The 2026 Senior Notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under the Company's revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of certain of the Company's future restricted subsidiaries that do not guarantee the 2026 Senior Notes.

The 2026 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company's or any of its Guarantors’ equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company’s affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2026 Senior Notes (the "2026 Senior Notes Indenture") also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2026 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2026 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2026 Senior Notes may declare all outstanding 2026 Senior Notes to be due and payable immediately.

Debt Issuance Costs

As of December 31, 2019 and 2018, the Company had debt issuance costs net of accumulated amortization of $2.9 million and $3.3 million, respectively, related to its credit facility which has been reflected on the Company’s consolidated balance sheet within the line item other non-current assets. As of December 31, 2019 and 2018, the Company had debt issuance costs net of accumulated amortization of $14.4 million and $17.3 million, respectively, related to its 2024 and 2026 Senior Notes, which have been reflected on the Company's consolidated balance sheets within the line item Senior Notes, net of unamortized debt issuance costs. Upon the redemption of the Company's 2021 Senior Notes in January and February 2018, the Company accelerated the amortization of the remaining $9.4 million of unamortized debt issuance costs. These expenses were recorded in the consolidated statements of operations within the interest expense line item. Debt issuance costs include origination, legal, engineering, and other fees incurred in connection with the Company’s credit facility and Senior Notes. For the years ended December 31, 2019, 2018, and 2017, the Company recorded amortization expense related to the debt issuance costs of $5.5 million, $13.2 million and $4.3 million, respectively.

Interest Incurred on Long-Term Debt

For the years ended December 31, 2019, 2018 and 2017, the Company incurred interest expense on long-term debt of $91.5 million, $82.7 million and $58.7 million, respectively, and the Company capitalized interest expense on long-term debt of $7.2 million, $8.2 million and $11.1 million, respectively, for the years ended December 31, 2019, 2018 and 2017, which has been reflected in the Company’s consolidated financial statements. Also included in interest expense for the year ended December 31, 2018 was a make-whole premium of $35.6 million related to the Company's repayment of its 2021 Senior Notes in January and February 2018. Also included in interest expense for the year ended December 31, 2017 is a prepayment penalty of $4.3 million related to the Company’s repayment of its Second Lien Notes in July 2016.

Senior Note Repurchase Program

On January 4, 2019, the Board of Directors authorized a program to repurchase up to $100.0 million of the Company’s Senior Notes. The Company’s Senior Notes Repurchase Program is subject to restrictions under the Credit Facility and does not obligate the Company to acquire any specific nominal amount of Senior Notes. During 2019, the Company repurchased 2026 Senior Notes with a nominal value of $49.8 million for $39.3 million in connection with the Senior Notes Repurchase Program. Interest expense for the year ended December 31, 2019 included a $10.5 million gain on debt repurchase related to the Company's Senior Note Repurchase Program. The Senior Note Repurchase Program had no impact to interest expense for the years ended December 31, 2018 and 2017.

Note 7—Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, as described below. The Company has utilized swaps, put options and call options to reduce the effect of price changes on a portion of the Company's future oil and natural gas production.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of the Company's purchased put options have deferred premiums. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

The Company combines swaps, purchased put options, purchased call options, sold put options and sold call options in order to achieve various hedging strategies. Some examples of the Company's hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of the Company's use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with ten counterparties, all of whom are lenders under our credit agreement. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. There are no credit-risk-related contingent features or circumstances in which the features could be triggered in derivative instruments that are in a net liability position at the end of the reporting period.

The Company's commodity derivative contracts as of December 31, 2019 are summarized below:

	2020	2021	2022	2023
NYMEX WTI Crude Swaps:				
Notional volume (Bbl)	3,200,000	3,900,000	1,020,000	900,000
Weighted average fixed price ($/Bbl)	$ 59.81	$ 57.17	$ 54.84	$ 54.87
NYMEX WTI Crude Purchased Puts:				
Notional volume (Bbl)	9,725,000	3,600,000	—	—
Weighted average purchased put price ($/Bbl)	$ 54.99	$ 54.17	$ —	$ —
NYMEX WTI Crude Sold Calls:				
Notional volume (Bbl)	9,725,000	3,600,000	—	—
Weighted average sold call price ($/Bbl)	$ 62.04	$ 61.93	$ —	$ —
NYMEX WTI Crude Sold Puts:				
Notional volume (Bbl)	12,250,000	7,500,000	600,000	600,000
Weighted average sold put price ($/Bbl)	$ 42.91	$ 43.28	$ 43.00	$ 43.00
NYMEX HH Natural Gas Swaps:				
Notional volume (MMBtu)	35,400,000	—	—	—
Weighted average fixed price ($/MMBtu)	$ 2.75	$ —	$ —	$ —
NYMEX HH Natural Gas Purchased Puts:				
Notional volume (MMBtu)	600,000	—	—	—
Weighted average purchased put price ($/MMBtu)	$ 2.90	$ —	$ —	$ —
NYMEX HH Natural Gas Sold Calls:				
Notional volume (MMBtu)	600,000	—	—	—
Weighted average sold call price ($/MMBtu)	$ 3.48	$ —	$ —	$ —
CIG Basis Gas Swaps:				
Notional volume (MMBtu)	45,600,000	—	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.61)	$ —	$ —	$ —

The following tables detail the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the balance sheets (in thousands):

	As of December 31, 2019				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offset in the Balance Sheet(1)**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet(2)**	**Net Amounts(3)**
Current assets	$ 48,605	$ (31,051)	$ 17,554	$ —	$ 30,783
Non-current assets	38,034	(24,805)	13,229	—	—
Current liabilities	(33,049)	31,051	(1,998)	—	(2,106)
Non-current liabilities	(24,913)	24,805	(108)	—	—

	As of December 31, 2018				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offset in the Balance Sheet(1)**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet(2)**	**Net Amounts(3)**
Current assets (4)	$ 115,852	$ (66,945)	$ 48,907	$ (192)	$ 57,147
Non-current assets	17,217	(8,785)	8,432	—	—
Current liabilities (4)	(67,141)	66,945	(196)	192	(4)
Non-current liabilities	(8,785)	8,785	—	—	—

(1) Agreements are in place that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.
(2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement which are not netted on the balance sheet. There are no amounts of related financial collateral received or pledged.
(3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line, and all counterparties in a net liability position are shown in the current liability line.
(4) Gross current liabilities include a deferred premium liability of $7.7 million related to the Company's deferred put premiums. Gross current assets include a deferred premium asset of $0.8 million related to the Company's deferred put premiums.

The table below sets forth the commodity derivatives loss for the years ended December 31, 2019, 2018 and 2017 (in thousands). Commodity derivatives loss are included under other income (expense).

	For the Year Ended December 31,		
	2019	**2018**	**2017**
Commodity derivatives loss	$ (37,107)	$ (8,554)	$ (36,332)

Note 8—Asset Retirement Obligations

The Company follows accounting for asset retirement obligations in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The Company’s asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable local, state and federal laws, and applicable lease terms. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred; the Company’s credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and gas properties using the unit of production method.

The following table summarizes the activities of the Company’s asset retirement obligations for the periods indicated (in thousands):

	For the Year Ended December 31,	
	2019	**2018**
Balance beginning of period	$ 69,791	$ 69,540
Liabilities incurred or acquired	978	2,136
Liabilities settled	(29,305)	(13,869)
Revisions in estimated cash flows[1]	49,050	6,800
Accretion expense	5,394	5,184
Balance end of period	$ 95,908	$ 69,791

(1) Revisions in estimated cash flows during the year ended December 31, 2019 and 2018 were primarily due to changes in estimates of costs to be incurred to plug and abandon wells and changes in estimated dates of abandonment.

Note 9—Fair Value Measurements

ASC 820, *Fair Value Measurement and Disclosure*, establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices are available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability;
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

The financial assets and liabilities are 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. There were no transfers between levels during any periods presented below.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2019 and 2018 by level within the fair value hierarchy (in thousands):

	Fair Value Measurement at December 31, 2019			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 30,783	$ —	$ 30,783
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 2,106	$ —	$ 2,106

	Fair Value Measurement at December 31, 2018			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 57,339	$ —	$ 57,339
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 196	$ —	$ 196

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the tables above:

Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market based approach that takes into account several factors, including quoted market prices in active markets, implied market volatility factors, quotes from third parties, the credit rating of each counterparty, and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. Derivative instruments utilized by the Company consist of swaps, put options, and call options. The oil and natural gas derivative markets are highly active. Although the Company's derivative instruments are valued using public indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Financial Instruments

The Company’s financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at variable rates over the term of the loan. The fair values of the 2024 Senior Notes and 2026 Senior Notes were derived from available market data. As such, the Company has classified the 2024 Senior Notes and 2026 Senior Notes as Level 2. Please refer to *Note 6 — Long-Term Debt* for further information. The Company's policy is to recognize transfers between levels at the end of the period. This disclosure (in thousands) does not impact the Company's financial position, results of operations or cash flows.

	At December 31, 2019		At December 31, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit Facility	$ 470,000	$ 470,000	$ 285,000	$ 285,000
2024 Senior Notes(1)	394,824	250,000	393,866	330,000
2026 Senior Notes(2)	690,953	420,113	738,793	558,750

(1) The carrying amount of the 2024 Senior Notes includes unamortized debt issuance costs of $5.2 million and $6.1 million as of December 31, 2019 and 2018, respectively.
(2) The carrying amount of the 2026 Senior Notes includes unamortized debt issuance costs of $9.2 million and $11.2 million as of December 31, 2019 and 2018, respectively.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. These assets and liabilities are not measured at fair value on a recurring basis but are subject to fair value adjustments when facts and circumstances arise that indicate a need for remeasurement.

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate, and at least annually, a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash flows of proved property. The Company calculates the estimated fair values of its proved property oil and gas assets using a discounted future cash flow model. Significant inputs associated with the calculation of discounted future net cash flows include estimates of (i) recoverable reserves, (ii) production rates, (iii) future operating and development costs, (iv) future commodity prices, and (v) a market-based weighted average cost of capital. The Company utilized the NYMEX strip pricing, adjusted for differentials, to value the reserves. These are classified as Level 3 fair value assumptions. At December 31, 2019, the Company’s estimate of commodity prices for purposes of determining discounted future cash flows ranged from a 2020 price of $59.03 per barrel of oil decreasing to a 2021 price of $54.38 per barrel of oil and decreasing further to a 2024 price of $51.44 per barrel of oil. Natural gas prices ranged from a 2020 price of $2.28 per Mcf increasing to a 2024 price of $2.49 per Mcf. NGL prices ranged from a 2020 price of $15.84 per barrel decreasing to a 2024 price of $13.80 per barrel. These prices were then adjusted for location and quality differentials. The expected future net cash flows were discounted using a rate of 11.6 percent.

For the years ended December 31, 2019 and 2018, respectively, the Company recognized $14.5 million and $16.2 million in impairment expense on its proved oil and gas properties related to assets in its northern field as the fair value did not exceed the Company's carrying amount attributable primarily to certain downward adjustments to the Company’s economically recoverable proved oil and natural gas reserves. For the year ended December 31, 2019, the Company recognized $1.3 billion in impairment expense on its proved oil and gas properties related to assets in its Core DJ Basin field as the fair value did not exceed the Company's carrying amount attributable primarily to certain downward adjustments to the Company’s reserves due to expirations due to the SEC five year drilling rule caused by the change in business strategy to focus on cash flow rather than maximizing production and reserves growth. No impairment expense was recognized for the year ended

December 31, 2018 on proved oil and gas properties in the Company's Core DJ Basin field. No impairment expense was recognized for the year ended December 31, 2017 on proved oil and gas properties.

The Company applies the provisions of ASC 350, *Intangibles-Goodwill and Other*. Goodwill represents the excess of the purchase price over the estimated value of the net assets acquired in business combinations. The Company tested goodwill for impairment annually on September 30, or whenever other circumstances or events indicate that the carrying amount of goodwill may not be recoverable. The goodwill test was performed at the reporting unit level, which represented the Company’s oil and gas operations in its Core DJ Basin field. If indicators of impairment are determined to exist, an impairment charge is recognized if the carrying value of goodwill exceeds its implied fair value. Any sharp prolonged decreases in the prices of oil and natural gas as well as continued declines in the quoted market price of the Company’s common shares could change the estimates of the fair value of the reporting unit and could result in an impairment charge. The Company performed a quantitative assessment as of September 30, 2018, which concluded the fair value of the reporting unit was greater than its carrying amount. The Company identified triggering events as of December 31, 2018, due to the decrease in commodity pricing and the quoted market price of the Company's common shares compared to September 30, 2018. As such, the Company performed a quantitative assessment as of December 31, 2018, utilizing an income approach based on estimates of the expected discounted future cash flows of the reporting unit's oil and gas properties, which concluded the fair value of the reporting unit was not greater than its carrying amount. As a result, the Company recorded goodwill impairment of $54.2 million, the entirety of the balance, for the year ended December 31, 2018. As such, no test for goodwill impairment was necessary for the year ended December 31, 2019.

The Company’s other non-recurring fair value measurements include the purchase price allocations for the fair value of assets and liabilities acquired through business combinations. The fair value of assets and liabilities acquired through business combinations is calculated using a discounted cash flow approach using Level 3 inputs. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including risk-adjusted oil and gas reserves, commodity prices, development costs and operating costs, based on market participant assumptions. The fair value of assets or liabilities associated with purchase price allocations is on a non-recurring basis and is not measured in periods after initial recognition.

Note 10—Equity

Preferred Units

On July 3, 2018, Elevation entered into a securities purchase agreement (the "Securities Purchase Agreement") with a third party (the "Purchaser"), pursuant to which Elevation agreed to sell 150,000 Preferred Units (the "Elevation Preferred Units") of Elevation at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $150.0 million (the "Private Placement"), in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended (the "Securities Act"). The Private Placement closed on July 3, 2018 (the "Preferred Unit Closing Date"), funded on July 19, 2018 and resulted in net proceeds of approximately $141.9 million, $25.4 million of which was a reimbursement for previously incurred midstream capital expenditures and general and administrative expenses.

On July 10, 2019, Elevation closed on the issuance of an additional 100,000 Preferred Units of Elevation under an existing securities purchase agreement with a third party, pursuant to which Elevation had agreed to sell an additional 100,000 Elevation Preferred Units at a price of $990 per Elevation Preferred Unit with an aggregate liquidation preference of $100.0 million, and resulting in net proceeds of approximately $96.5 million, after deducting discounts and related offering expenses. The proceeds were to be used primarily for midstream capital expenditures.

These Preferred Units represent the noncontrolling interest presented on the consolidated balance sheets, consolidated statements of operations and consolidated statement of changes in stockholders' equity and noncontrolling interest. Elevation is a separate entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As of December 31, 2019, $10.7 million of cash was held by Elevation and is earmarked for construction of pipeline infrastructure to serve the development of acreage in its Hawkeye and Southwest Wattenberg areas. As of December 31, 2019 and 2018, Elevation capital expenditures represented all of the gathering systems and facilities line item in the consolidated balance sheets and the gathering systems and facilities additions in the consolidated statements of cash flows.

During the twenty-eight months following the Preferred Unit Closing Date (the "Preferred Unit Commitment Period"), Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional $250.0 million commitment. For the years ended December 31, 2019 and 2018, respectively, Elevation recognized $3.1 million and $1.8 million of commitment fees paid-in-kind included under the Preferred

Unit commitment fees and dividends paid-in-kind line item in the consolidated statements of changes in stockholders' equity and noncontrolling interest. No such fees were recognized for the year ended December 31, 2017.

The Elevation Preferred Units will entitle the Purchaser to receive quarterly dividends at a rate of 8.0% per annum. In respect of quarters ending prior to and including June 30, 2020, such dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, such dividend is payable solely in cash. Elevation recognized $16.9 million and $5.5 million of dividends paid-in-kind for the years ended December 31, 2019 and 2018, respectively, included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the consolidated statements of changes in stockholders' equity and noncontrolling interest. No such fees were recognized for the year ended December 31, 2017.

Series A Preferred Stock and Series B Preferred Units

On October 3, 2016, the Company issued $185.3 million in convertible preferred securities ("Series B Preferred Units"). The Series B Preferred Units were entitled to receive a cash dividend of 10% per year, payable quarterly in arrears, and the Company had the ability to pay up to 50% of the quarterly dividend in kind. The Series B Preferred Units converted in connection with the closing of the IPO in October 2016 into 185,280 shares of Series A Convertible Preferred Stock (the "Series A Preferred Stock") that are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and the Company has the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are paid in cash). During the first nine months of 2019, the Company incurred $8.2 million of dividends associated with the Series A Preferred Stock, or $44.13 per share. During the fourth quarter of 2019, the Company elected to pay the dividend in kind and increased the aggregate liquidation preference of the Series A Preferred Stock $4.6 million to $189.9 million. The Series A Preferred Stock is convertible into shares of our common stock at the election of the holders of the Series A Preferred Stock ("Series A Preferred Holders") at a conversion ratio per share of Series A Preferred Stock of 61.9195, and the Company may redeem the Series A Preferred Stock at any time for the liquidation preference, which is currently $189.9 million. In accordance with ASC Topic 470, Debt ("ASC 470"), the Company determined that the conversion feature of the Series A Preferred Stock represented a beneficial conversion feature. The fair value of the Company's common stock on the closing of the IPO was greater than the Series A Preferred Stock conversion price by approximately $32.7 million in aggregate. Under ASC 470, $32.7 million (the fair value of the beneficial conversion feature) of the proceeds received from the issuance of the Series B Preferred Units, subsequently converted to the Series A Preferred Stock, was allocated to additional paid-in capital. The beneficial conversion feature is required to be accreted on a non-cash basis over the approximate 60 month period between the issuance date and the required redemption date of October 15, 2021, or fully accreted upon an accelerated date of redemption or conversion, resulting in an increase of the Series A Convertible Preferred Stock presented on the Consolidated Balance Sheets. The accretion of the beneficial conversion feature of Series A Preferred Stock is presented as a decrease to additional paid-in capital on the changes in stockholders' equity and noncontrolling interest. As a result, approximately $6.6 million, $6.0 million and $5.4 million was accreted during the years ended December 31, 2019, 2018, and 2017, respectively. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash from funds legally available for such purpose in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Company and the Series A Preferred Stock Holders both have options to redeem the Series A Preferred Stock. The Company's option to convert the Series A Preferred Stock into common stock expired in October 2019. The Series A Preferred Stock mature on October 15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference. If the Series A Preferred Stock have not been converted into common equity or redeemed prior to April 15, 2021 (the Company can redeem at any time), the Company's Credit Facility will mature on April 15, 2021. For additional discussion, please see *Note 6 — Long-Term Debt*.

Stock Repurchase Program

On November 19, 2018, the Company announced that the Board of Directors had authorized a program to repurchase up to $100.0 million of the Company's common stock ("Stock Repurchase Program"). On April 1, 2019, the Company announced the Board of Directors had authorized an extension and increase to the ongoing Stock Repurchase Program bringing the total amount authorized to $163.2 million ("Extended Stock Repurchase Program"). The Stock Repurchase Program and the Extended Stock Repurchase Program were both completed during 2019, bringing the total amount of common stock repurchased to 38.2 million shares for $163.2 million and a weighted average share price of $4.27. For the years ended December 31, 2019 and 2018, the Company repurchased approximately 34.1 million and 4.1 million shares of its common stock for $137.0 million and $26.2 million, respectively.

Note 11—Income Taxes

At the end of 2017 the Tax Cuts and Jobs Act (the “TCJA") was enacted making significant changes to the Internal Revenue Code. As a result, the Company remeasured the deferred tax assets and liabilities as of December 31, 2017 at the rate in which they are expected to reverse. This re-measurement of deferred tax assets and liabilities required the Company to analyze and record a one-time adjustment to reduce the overall deferred tax liability in the consolidated balance sheets and reflect a corresponding income tax benefit in the consolidated statement of operations for the year ended December 31, 2017. This resulted in the recording of an income tax benefit of $23.4 million, as well as a corresponding reduction in the deferred tax liability as of December 31, 2017. During the third quarter of 2018, we completed the accounting for the income tax effect of the TCJA’s limit on compensation under Internal Revenue Code Sec. 162(m) and stock-based compensation for covered employees. This resulted in a $0.4 million reduction in deferred tax assets that had been recorded as a provision amount as of December 31, 2017. The Company believes that the accounting is complete regarding the revaluation of the deferred tax balances and there are no remaining provisional amounts associated with the TCJA as of December 31, 2018. The Company is aware that the Internal Revenue Service has issued proposed regulations regarding the TCJA and has incorporated this guidance into its current tax policy. The Company will continue to monitor and analyze the impact of future guidance and any final regulations as they become available.

The components of the income tax expense (benefit) were as follows (in thousands):

	For the Year Ended December 31,		
	2019	2018	2017
Current:			
Federal	$ —	$ —	$ —
State, net of federal benefit	—	—	—
Total current income tax expense (benefit)	$ —	$ —	$ —
Deferred:			
Federal	$ (93,245)	$ 56,943	$ (61,719)
State, net of federal benefit	(15,931)	9,907	(1,981)
Total deferred income tax expense (benefit)	$ (109,176)	$ 66,850	$ (63,700)
Income tax expense (benefit)	$ (109,176)	$ 66,850	$ (63,700)

The following table reconciles the income tax expense (benefit) with income tax expense at the federal statutory rate (in thousands):

	For the Year Ended December 31,		
	2019	2018	2017
Net income (loss) before income taxes	$ (1,476,596)	$ 188,705	$ (108,108)
Federal income taxes at statutory rate	(310,085)	39,628	(37,838)
State income taxes, net of federal benefit	(52,723)	9,907	(3,118)
Impact of goodwill impairment	—	11,386	—
Partnership income excluded	(3,558)	—	—
Nondeductible stock-based compensation	9,436	5,088	2,264
Enactment of the Tax Cuts and Jobs Act	—	—	(23,412)
Other	1,626	841	(1,596)
Valuation allowance	246,128	—	—
Income tax expense (benefit)	(109,176)	66,850	(63,700)
Net income (loss)	$ (1,367,420)	$ 121,855	$ (44,408)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows (in thousands):

	As of December 31,	
	2019	2018
Deferred Tax Assets:		
Net operating loss carryforward	$ 266,446	$ 149,399
Stock-based compensation	17,138	17,242
Intangible drilling costs - Section 59(e)	98,631	127,604
Property taxes	16,812	22,277
Other	—	10,856
Total deferred tax assets	$ 399,027	$ 327,378
Deferred Tax Liabilities:		
Excess basis of oil and gas properties	$ (134,484)	$ (426,428)
Commodity derivatives	(7,071)	(10,126)
Other	(11,344)	—
Total deferred tax liabilities	(152,899)	(436,554)
Less: Valuation allowance	$ (246,128)	$ —
Deferred Taxes, net	$ —	$ (109,176)

Management considers whether some portion or all of the deferred tax assets will be realized based on a more likely than not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. The Company has net operating loss carryforwards (NOLs) for U.S. income tax purposes that have been generated from the Company's operations through December 31, 2019 of approximately $1.1 billion, of which $833.6 million was generated before January 1, 2018 and are not subject to the 80 percent limitation of taxable income. Such NOLs will expire beginning in 2036. As of December 31, 2019, the Company had $400.0 million of intangible drilling costs that were capitalized under Code Section 59(e). We believe it is more likely than not that the benefit from net operating loss carryforwards will not be fully realized. In recognition of this risk, we have provided a valuation allowance on the deferred tax assets.

The utilization of such NOL carryforwards may be limited upon the occurrence of certain ownership changes as stipulated in Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"). As of December 31, 2019, the Company determined that the statutory provision of Section 382 will not limit the Company’s ability to realize future tax benefits. The Company files income tax returns in the U.S. federal jurisdiction and in Colorado. The statute of limitations related to the 2016, 2017 and 2018 tax returns is open through 2020, 2021 and 2022, respectively; however, the ability for the tax authority to adjust the NOL will continue until three years after the NOL is utilized.

As of December 31, 2019, the Company believes that it has no liability for uncertain tax positions. If the Company were to determine there are any uncertain tax positions, the Company would recognize the liability and related interest and penalties within income tax expense. As of December 31, 2019, the Company had no provision for interest or penalties related to uncertain tax positions.

Note 12—Stock-Based Compensation

Extraction Long Term Incentive Plan

In October 2016, the Board of Directors adopted the Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (the "2016 Plan" or "LTIP"), pursuant to which employees, consultants, and directors of the Company and its affiliates performing services for the Company are eligible to receive awards. The 2016 Plan provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, other stock-based awards, substitute awards, annual incentive awards, and performance awards intended to align the interests of participants with those of stockholders. In May 2019, the Company's stockholders approved the amendment and restatement of the Company's 2016 Long Term Incentive Plan. The amended and restated 2016 Long Term Incentive Plan provides a total reserve of 32.2 million shares of common stock for issuance pursuant to awards under the LTIP. Extraction has granted awards under the LTIP to certain directors, officers and employees, including stock options, restricted stock units, performance stock awards, performance stock units, performance cash awards and cash awards.

Restricted Stock Units

Restricted stock units ("RSUs") granted under the LTIP generally vest over either a one or three-year service period, with 100% vesting in year one or 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock pursuant to the terms of the LTIP. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost. As of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU No. 2016-09.

The Company recorded $23.8 million, $27.9 million and $31.8 million of stock-based compensation costs related to RSUs for the years ended December 31, 2019, 2018 and 2017, respectively. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. As of December 31, 2019, there was $12.0 million of total unrecognized compensation costs related to the unvested RSUs granted to certain directors, officers and employees that is expected to be recognized over a weighted average period of 1.7 years.

The following table summarizes the RSU activity from January 1, 2017 through December 31, 2019 and provides information for RSUs outstanding at the dates indicated.

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested RSUs at January 1, 2017	3,237,500	$ 21.41
Granted	1,369,083	$ 16.37
Forfeited	(445,366)	$ 19.85
Vested	(1,254,744)	$ 20.85
Non-vested RSUs at December 31, 2017	2,906,473	$ 19.51
Granted	1,226,768	$ 12.53
Forfeited	(95,725)	$ 14.94
Vested	(935,181)	$ 19.44
Non-vested RSUs at December 31, 2018	3,102,335	$ 16.91
Granted	1,905,918	$ 4.75
Forfeited	(469,035)	$ 10.54
Vested	(1,903,453)	$ 18.20
Non-vested RSUs at December 31, 2019	2,635,765	$ 8.32

Performance Stock Awards

The Company granted performance stock awards ("PSAs") to certain executives under the LTIP in October 2017, March 2018 and April 2019. The number of shares of the Company's common stock that may be issued to settle these various PSAs ranges from zero to two times the number of PSAs awarded. PSA's that settle in cash are presented as liability based awards. Generally, the shares issued for PSAs are determined based on the satisfaction of a time-based vesting schedule and a weighting of one or more of the following: (i) absolute total stockholder return ("ATSR"), (ii) relative total stockholder return ("RTSR"), as compared to the Company's peer group and (iii) cash return on capital invested ("CROCI") or return on invested capital ("ROIC") measured over a three-year period and vest in their entirety at the end of the three-year measurement period. Any PSAs that have not vested at the end of the applicable measurement period are forfeited. The vesting criterion that is associated with the RTSR is based on a comparison of the Company's total shareholder return for the measurement period compared to that of a group of peer companies for the same measurement period. As the ATSR and RTSR vesting criteria are linked to the Company's share price, they each are considered a market condition for purposes of calculating the grant-date fair value of the awards. The vesting criterion that is associated with the CROCI and ROIC are considered a performance condition for purposes of calculating the grant-date fair value of the awards.

The fair value of the PSAs 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. Those 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 PSAs, the Company cannot predict with certainty the path its stock price or the stock prices of its peer will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Monte Carlo Model, is deemed an appropriate method by which to determine the fair value of the PSAs. 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 assumptions used in valuing the PSAs granted were as follows:

	For the Years Ended		
	December 31, 2019	December 31, 2018	December 31, 2017
Risk free rates	2.3 %	2.3 %	1.5 %
Dividend yield	—	—	—
Expected volatility	58.5 %	59.9 %	45.0 %

The Company recorded $7.3 million, $5.7 million and $0.8 million of stock-based compensation costs related to PSAs for the years ended December 31, 2019, 2018 and 2017, respectively. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. As of December 31, 2019, there was $5.4 million of total unrecognized compensation costs related to the unvested PSAs granted to certain executives that is expected to be recognized over a weighted-average period of 1.2 years.

The following table summarizes the PSA activity from January 1, 2017 through December 31, 2019 and provides information for PSAs outstanding at the dates indicated.

	Number of Shares[(1)]	Weighted Average Grant Date Fair Value
Non-vested PSAs as of January 1, 2017	—	$ —
Granted	832,163	$ 8.85
Forfeited	—	$ —
Vested	—	$ —
Non-vested PSAs as of December 31, 2017	832,163	$ 8.85
Granted	1,961,920	$ 9.06
Forfeited	—	$ —
Vested	—	$ —
Non-vested PSAs as of December 31, 2018	2,794,083	$ 9.00
Granted	1,224,696	$ 5.63
Forfeited	(418,229)	$ 8.17
Cancelled	(737,360)	$ 8.85
Vested	—	$ —
Non-vested PSAs as of December 31, 2019	2,863,190	$ 7.72

(1) The number of awards assumes that the associated maximum vesting 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 one for the 2017 and 2018 grants and ranges from zero to two for the 2019 grants, depending on the level of satisfaction of the vesting condition.

Stock Options

Expense on the stock options are recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options was measured at the grant date using the Black-Scholes valuation model. The Company utilized the "simplified" method to estimate the expected term of the stock options granted as at the time there was limited historical exercise data available in estimating the expected term of the stock options. Expected volatility is based on the volatility of the historical stock prices of the Company’s peer group. The risk-free rates are based on the yields of U.S. Treasury instruments with comparable terms. A dividend yield and forfeiture rate of zero were assumed. Stock options granted under the

LTIP vest ratably over three years and are exercisable immediately upon vesting through the tenth anniversary of the grant date. To fulfill options exercised, the Company issues new shares.

The Company recorded $12.1 million, $15.1 million and $15.7 million of stock-based compensation costs related to the stock options for the years ended December 31, 2019, 2018 and 2017, respectively. These costs were included in the consolidated statements of operations within the general and administrative expenses line item. As of December 31, 2019, there are no remaining unrecognized compensation costs related to the stock options granted to certain executives.

The following table summarizes the assumptions used for the Black-Scholes valuation model to calculate the stock-based compensation expense for the year ended December 31, 2017. No stock options were granted for the years ended December 31, 2019 and 2018.

	For the Year Ended December 31, 2017
Risk free rates	2.0 %
Dividend yield	—
Expected volatility	58.9 %
Expected term (in years)	6.0

The weighted average fair value at the date of grant for stock options granted is as follows:		
Weighted average per share	$	8.66
Total options granted		744,428
Total weighted average fair value of options granted (in thousands)	$	6,445

The following table summarizes the stock option activity from January 1, 2017 through December 31, 2019 and provides information for stock options outstanding at the dates indicated.

	Number of Shares	Weighted Average Exercise Price		Aggregate Intrinsic Value (in thousands)	
Non-vested Stock Options at January 1, 2017	4,500,000	$	19.00	$	4,680
Granted	744,428	$	15.53	$	—
Forfeited	—	$	—	$	—
Vested	(1,748,138)	$	18.52	$	—
Non-vested Stock Options at December 31, 2017	3,496,290	$	18.50	$	—
Granted	—	$	—	$	—
Forfeited	—	$	—	$	—
Vested	(1,748,142)	$	18.49	$	—
Non-vested Stock Options at December 31, 2018	1,748,148	$	18.50	$	—
Granted	—	$	—	$	—
Forfeited	—	$	—	$	—
Vested	(1,748,148)	$	18.50	$	—
Non-vested Stock Options at December 31, 2019	—	$	—	$	—

The following table summarizes information about outstanding and exercisable stock options as of December 31, 2019.

Outstanding and Exercisable Options					
Options	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price		Aggregate Intrinsic Value (thousands)	
4,500,000	6.9 years	$	19.00	$	—
744,428	7.8 years	$	15.53	$	—
5,244,428	7.0 years	$	18.50	$	—

Incentive Restricted Stock Units

Officers of the Company contributed 2.7 million shares of common stock to Extraction Employee Incentive, LLC ("Employee Incentive"), which is owned solely by certain officers of the Company. Employee Incentive issued restricted stock units ("Incentive RSUs") to certain employees. Incentive RSUs vested over a three-year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. On July 17, 2017, the partners of Employee Incentive amended the vesting schedule in which 25% vested immediately and the remaining Incentive RSUs vested 25%, 25% and 25% each six months thereafter, over the remaining 18 month service period. Grant date fair value was determined based on the value of Extraction's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost. As of January 1, 2017, the Company elected to account for stock-based compensation forfeitures as they occur, as a result of the adoption of ASU No. 2016-09.

The Company recorded $0.8 million, $19.6 million and $17.3 million of stock-based compensation costs related to Incentive RSUs for the years ended December 31, 2019, 2018 and 2017, respectively. These costs were included in the statements of operations within the general and administrative expenses line item. As of December 31, 2019, there are no remaining unrecognized compensation costs related to the Incentive RSUs granted to certain employees.

The following table summarizes the Incentive RSU activity from January 1, 2017 through December 31, 2019 and provides information for Incentive RSUs outstanding at the dates indicated.

	Number of Shares		Weighted Average Grant Date Fair Value
Non-vested Incentive RSUs at January 1, 2017	2,714,368	$	—
Granted	—	$	—
Forfeited	(710,993)	$	20.45
Vested	(507,200)	$	—
Non-vested Incentive RSUs at December 31, 2017	1,496,175	$	20.45
Granted	—	$	—
Forfeited	(41,400)	$	20.45
Vested	(978,775)	$	20.45
Non-vested Incentive RSUs at December 31, 2018	476,000	$	20.45
Granted	—	$	—
Forfeited	—	$	—
Vested	(476,000)	$	20.45
Non-vested Incentive RSUs at December 31, 2019	—	$	—

Note 13—Earnings (Loss) Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) available to common shareholders by the weighted-average number of shares outstanding during the period. Diluted EPS reflects the potential dilution of securities that could share in the earnings available to common shareholders of the Company. The Company uses the "if-converted" method to determine potential dilutive effects of Series A Preferred Stock and the treasury method to determine the potential dilutive effects of outstanding restricted stock awards and stock options.

The components of basic and diluted EPS were as follows (in thousands, except per share data):

	For the Year Ended December 31,		
	2019	2018	2017
Basic and Diluted Income (Loss) per Share			
Net income (loss)	$ (1,367,420)	$ 121,855	$ (44,408)
Less: Noncontrolling interest	(19,992)	(7,287)	—
Less: Adjustment to reflect Series A Preferred Stock dividend	(12,796)	(10,885)	(10,885)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(6,640)	(5,984)	(5,394)
Net income (loss) available to common shareholders, basic and diluted	$ (1,406,848)	$ 97,699	$ (60,687)
Weighted Average Common Shares Outstanding (1) (2) (3)			
Basic and diluted	151,481	174,748	171,910
Net Income (Loss) Allocated to Common Shareholders per Common Share			
Basic and diluted	$ (9.29)	$ 0.56	$ (0.35)

(1) For the year ended December 31, 2019, 2,635,765 potentially dilutive shares associated with restricted stock awards outstanding were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 5,244,428 common shares for stock options were excluded as they were out of the money and 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded.
(2) For the year ended December 31, 2018, 3,102,335 potentially dilutive shares associated with restricted stock awards outstanding were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 5,244,428 common shares for stock options were excluded as they were out of the money and 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded.
(3) For the year ended December 31, 2017, 8,566,983 potentially dilutive shares were not included in the calculation above, as they had an anti-dilutive effect on EPS, including restricted stock awards, stock options outstanding and performance stock awards contingently issuable, if December 31, 2017 was the end of the measurement period. Additionally, the 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded.

Note 14—Commitments and Contingencies

Leases

The Company has entered into operating leases for certain office facilities, compressors and office equipment. The Company leases two office spaces in Denver, Colorado and one office space in Houston, Texas under separate operating lease agreements. The Denver, Colorado leases expire on February 29, 2020 and May 31, 2028, respectively. The Houston lease expires on January 31, 2022. Rent expense was $3.4 million and $2.3 million for the years ended December 31, 2018 and 2017, respectively. On January 1, 2019, the Company adopted ASC Topic 842, Leases, using the modified retrospective approach. Refer to *Note 5—Leases* for additional information.

Drilling Rigs

As of December 31, 2019, the Company was subject to commitments on two drilling rigs contracted through May 2020 and February 2021. These costs are capitalized within proved oil and gas properties on the consolidated balance sheets and are included as short-term and long-term lease costs in *Note 5—Leases*. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate remaining amount of approximately $13.3 million as of December 31, 2019, as required under the terms of the contracts.

Maturities of operating lease liabilities, associated with Right-of-Use assets and including imputed interest, as of December 31, 2019, were as follows (in thousands):

	Operating Leases
2020	$ 19,040
2021	5,247
2022	2,211
2023	2,246
2024	2,301
Thereafter	8,273
Total lease payments	$ 39,318
Less imputed interest [(1)]	(4,735)
Present value of lease liabilities [(2)]	$ 34,583

(1) Calculated using the estimated interest rate for each lease.

(2) Of the total present value of lease liabilities, $17.4 million was recorded in "Accounts payable and accrued liabilities" and $17.2 million was recorded in "Other non-current liabilities" on the consolidated balance sheets.

As of December 31, 2018, minimum future contractual payments for operating leases under the scope of ASC 840 for certain office facilities and drilling rigs are as follows (in thousands):

	Operating Leases
2019	$ 12,713
2020	3,371
2021	3,385
2022	3,360
2023	3,411
Thereafter	15,719
Total lease payments	$ 41,959

Delivery Commitments

As of December 31, 2019, the Company's oil marketer is subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. In May 2017, the Company amended its agreement with its oil marketer that requires it to sell all of its crude oil from an area of mutual interest in exchange for a make-whole provision that allows the Company to satisfy any minimum volume commitment deficiencies incurred by its oil marketer with future barrels of crude oil in excess of their minimum volume commitment during the contract term. In May 2019, the Company extended the term of this agreement through October 31, 2020 subject to an evergreen provision thereafter where either party can provide a six month notice of termination beginning November 1, 2020. Due to the contract termination date, the amount of consideration recognized in revenue is reduced. See *Note 2- Basis of Presentation and Significant Accounting Policies - Contract Balances.* The Company has posted a letter of credit for this agreement in the amount of $40.0 million. The Company may be required to pay a shortfall fee for any volume deficiencies under these commitments. The aggregate remaining amount of estimated payments under these agreements is approximately $679.8 million.

The Company has two long-term crude oil gathering commitments with an unconsolidated subsidiary, in which the Company has a minority ownership interest. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The Company may be required to pay a shortfall fee for any volume deficiencies under this commitment. The second agreement commenced in July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The Company may be required to pay a shortfall fee for any volume deficiencies under this commitment. The aggregate remaining amount of estimated payments under these agreements is approximately $120.3 million.

In February 2019, the Company entered into two long-term gas gathering and processing agreements with third-party midstream providers. One of the agreements additionally includes a long-term NGL sales commitment for take-in-kind NGLs from other processing agreements. The first agreement commenced in November 2019 and has a term of twenty years with a minimum volume commitment of 251 Bcf to be delivered within the first seven years. The annual commitments over seven years are to be delivered on an average 85,000 Mcf/d in year one, 125,000 Mcf/d in year two, 140,000 Mcf/d in year three, 118,000 Mcf/d in year four, 98,000 Mcf/d in year five, 70,000 Mcf/d in year six and 52,000 Mcf/d in year seven. The aggregate remaining amount of estimated payments under this agreement is approximately $308.4 million. The second agreement commenced on January 2020 and has a term of ten years with an annual minimum volume commitment of 13.0 Bcf in years one through ten. The second agreement also includes a commitment to sell take-in-kind NGLs of 4,000 Bbl/d in year one and 7,500 Bbl/d in years two through seven with the ability to roll up to a 10% shortfall in a given month to the subsequent month. The Company may be required to pay a shortfall fee for any volume deficiencies under these commitments, calculated based on the applicable gathering and processing fees and/or, with respect to the NGL commitment, the NGL transport cost. Under its current drilling plans, the Company expects to meet these volume commitments.

The summary of these minimum volume commitments as of December 31, 2019, was as follows:

	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
2020	8,935	33,550	14,527
2021	10,349	46,540	18,106
2022	9,128	49,758	17,421
2023	9,490	41,850	16,465
2024	9,516	34,160	15,209
Thereafter	29,308	40,260	36,018
Total	76,726	246,118	117,746

In collaboration with several other producers and a midstream provider, on December 15, 2016 and August 7, 2017, the Company agreed to participate in expansions of natural gas gathering and processing capacity in the DJ Basin. The plan includes two new processing plants as well as the expansion of related gathering systems. The first plant commenced operations in August 2018 and the second plant commenced operations in July 2019. The Company's share of these commitments will require an incremental 51.5 and 20.6 MMcf per day, respectively, over a baseline volume of 65 MMcf per day to be delivered after the plants' in-service dates for a period of seven years thereafter. The Company may be required to pay a shortfall fee for any incremental volume deficiency under these commitments. These contractual obligations can be reduced by the Company's proportionate share of the collective volumes delivered to the plants by other third-party incremental volumes available to the midstream provider at the new facilities that are in excess of the total commitments. The Company is also required for the first three years of each contract to guarantee a certain target profit margin on these volumes sold.

In July 2019, the Company entered into three long-term contracts to supply 125,000 dekatherms of residue gas per day for five years to a transportation company. While our production is expected to satisfy these contracts, the aggregate remaining amount of estimated commitment assuming no production is $32.7 million. The Company has posted a letter of credit for this agreement in the amount of $8.7 million.

The aggregate remaining amount of estimated remaining payments under these agreements is $1,141.2 million.

Elevation Gathering Agreements

In November 2018, Extraction entered into the Elevation Gathering Agreements. Under the agreements, the Company agreed to drill 100 wells in Broomfield and 325 wells in Hawkeye by December 31, 2023 if both facilities are to be built. If Extraction fails to complete the wells by the commitment deadline, then it would be deemed to be in breach of the agreement and Elevation could (at Elevation's discretion) be entitled to make a claim for damages against Extraction and its affiliates. The Elevation Gathering Agreements were amended in April 2019 to provide for, among other amendments, the inclusion of additional gathering facilities in Elevation's Badger facility. Pursuant to this amendment, if these additional gathering facilities are not completed by April 1, 2020, then within 30 days of such date Extraction would be required to make a payment to Elevation in the amount of 135% of all cost incurred by Elevation as of such date for the development and construction of such additional gathering facilities. Extraction does not expect to complete these additional gathering facilities by such date. As of December 31, 2019, the costs incurred by Elevation for these additional gathering facilities totaled $33.9 million. Extraction continues to work with Elevation’s financing partner in constructive discussions surrounding this target completion date. In December 2019, the Elevation Gathering Agreements were further amended such to provide Elevation additional connection fees that are consistent with market terms (the "Connect Fees"). In the fourth quarter of 2019, the Company incurred $19.5 million for connect fees pursuant to the Elevation Gathering Agreements and does not expect to incur more than the $23.5 million already paid during 2020 for the year ending December 31, 2020.

General

The Company is subject to contingent liabilities with respect to existing or potential claims, lawsuits, and other proceedings, including those involving environmental, tax, and other matters, certain of which are discussed more specifically below. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company’s estimates of the outcomes of these matters and its experience in contesting, litigating, and settling other matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which management currently believes will not have a material effect on the Company’s financial position, results of operations, or cash flows.

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost or the Company may be required to pay damages if certain performance conditions are not met.

Litigation and Legal Items

The Company is involved in various legal proceedings and reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the Company’s best interests. The Company has provided the necessary estimated accruals in the consolidated balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, the Company currently believes that the ultimate results of such proceedings will not have a material adverse effect on our business, financial position, results of operations or liquidity.

Environmental. Due to the nature of the natural gas and oil industry, the Company is exposed to environmental risks. The Company has various policies and procedures to minimize and mitigate the risks from environmental contamination or with respect to environmental compliance issues. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, the Company is not aware of any material environmental claims existing as of December 31, 2019 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws, compliance matters or other environmental liabilities will not be discovered on our properties. Accrued environmental liabilities are recorded in accounts payable and accrued liabilities on the consolidated balance sheets. The liability ultimately incurred with respect to a matter may exceed the related accrual.

COGCC Notices of Alleged Violations ("NOAVs"). The Company has received NOAVs from the COGCC for alleged compliance violations that the Company has responded to. At this time, the COGCC has not alleged any specific penalty amounts in these matters. The Company does not believe that any penalties that could result from these NOAVs will have a material effect on our business, financial condition, results of operations or liquidity, but they may exceed $100,000.

Note 15—Related Party Transactions

Office Lease with Related Affiliate

In April 2016, the Company subleased office space to Star Peak Capital, LLC, of which a member of the Board of Directors is an owner, for $1,400 per month. The sublease commenced on May 1, 2016 and expired on February 28, 2020.

2021 Senior Notes

Several 5% stockholders of the Company were also holders of the 2021 Senior Notes prior to the Tender Offer and the redemption of the 2021 Senior Notes. As of the initial issuance of the $550.0 million principal amount on the 2021 Senior Notes, such stockholders held $63.5 million.

2024 Senior Notes

Several 5% stockholders of the Company were also holders of the 2024 Senior Notes. As of the initial issuance in August 2017 of the $400.0 million principal amount on the 2024 Senior Notes, such stockholders held $54.9 million.

2026 Senior Notes

Several 5% stockholders of the Company were also holders of the 2026 Senior Notes. As of the initial issuance in January 2018 of the $750.0 million principal amount on the 2026 Senior Notes, such stockholders held $56.2 million.

Increased Ownership in an Unconsolidated Subsidiary

In May 2018, the Company exercised an option to increase its ownership percentage in an unconsolidated subsidiary funded with a $35.3 million promissory note. This note was extinguished with the transfer of units to the unconsolidated subsidiary. The Company also contributed an acreage dedication and minimum volume commitment. See *Note 14 — Commitments & Contingencies* for a description of the Company's minimum volume commitments.

Note 16—Segment Information

See *Note 2 — Basis of Presentation and Significant Accounting Policies - Segment Reporting* for a description of the Company's determination of its reportable segments. Prior to the fourth quarter of 2018, the Company had a single operating segment. The Company's Exploration and Production segment revenues are derived from third parties. The Company's Gathering and Facilities segment, also known as Elevation, commenced moving crude oil, natural gas and water through its Badger central gathering facility during the fourth quarter of 2019. The Gathering and Facilities segment had $6.9 million of revenue entirely from the Exploration and Production segment during 2019 and no revenue during 2018. Capital expenditures associated with gathering systems and facilities are being incurred to develop midstream infrastructure to support the Company's development of its oil and gas leasehold along with third-party activity.

Financial information of the Company's reportable segments was as follows for the years ended December 31, 2019 and 2018 (in thousands).

	For the Year Ended December 31, 2019			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from third parties	$ 905,374	$ 1,261	$ —	$ 906,635
Revenues from Extraction	—	5,618	(5,618)	—
Total Revenues	$ 905,374	$ 6,879	$ (5,618)	$ 906,635
Operating Expenses and Other Income (Expense):				
Direct operating expenses	$ (223,707)	$ (2,258)	$ 5,131	$ (220,834)
Depletion, depreciation, amortization and accretion	(523,122)	(1,415)	—	(524,537)
Interest income	449	1,379	—	1,828
Interest expense	(79,232)	—	—	(79,232)
Earnings in unconsolidated subsidiaries	—	2,285	—	2,285
Subtotal Operating Expenses and Other Income (Expense):	$ (825,612)	$ (9)	$ 5,131	$ (820,490)
Segment Assets	$ 2,554,893	$ 377,925	$ (5,861)	$ 2,926,957
Capital Expenditures	597,677	202,624	—	800,301
Investment in Equity Method Investees	—	44,584	—	44,584
Segment EBITDAX	607,560	3,653	(487)	610,726

	For the Year Ended December 31, 2018			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from third parties	$ 1,060,743	$ —	$ —	$ 1,060,743
Revenues from Extraction	—	—	—	—
Total Revenues	$ 1,060,743	$ —	$ —	$ 1,060,743
Operating Expenses and Other Income (Expense):				
Direct operating expenses	$ (209,169)	$ —	$ —	$ (209,169)
Depletion, depreciation, amortization and accretion	(435,736)	(39)	—	(435,775)
Interest income	461	1,467	—	1,928
Interest expense	(123,330)	—	—	(123,330)
Earnings in unconsolidated subsidiaries	319	2,544	—	2,863
Subtotal Operating Expenses and Other Income (Expense):	$ (767,455)	$ 3,972	$ —	$ (763,483)
Segment Assets	$ 3,896,966	$ 269,337	$ (276)	$ 4,166,027
Capital Expenditures	892,548	108,198	—	1,000,746
Investment in Equity Method Investees	—	15,487	—	15,487
Segment EBITDAX	658,565	1,187	—	659,752

The following table presents a reconciliation of Adjusted EBITDAX by segment to the GAAP financial measure of income (loss) before income taxes for the years ended December 31, 2019 and 2018 (in thousands). The Company had a single reportable segment during the year ended December 31, 2017, therefore no reconciliation is provided for this period.

	For the Year Ended December 31, 2019	For the Year Ended December 31, 2018
Reconciliation of Adjusted EBITDAX to Income (Loss) Before Income Taxes		
Exploration and production segment EBITDAX	$ 607,560	$ 658,565
Gathering and facilities segment EBITDAX	3,653	1,187
Elimination of intersegment transactions segment EBITDAX	(487)	—
Subtotal of Reportable Segments	$ 610,726	$ 659,752
Less:		
Depletion, depreciation, amortization and accretion	$ (524,537)	$ (435,775)
Impairment of long lived assets and goodwill	(1,337,996)	(70,928)
Exploration and abandonment expenses	(88,794)	(31,611)
Gain on sale of property and equipment and assets of unconsolidated subsidiary	(421)	136,834
Gain (loss) on commodity derivatives	(37,107)	(8,554)
Settlements on commodity derivative instruments	5,790	123,518
Premiums paid for derivatives that settled during the period	18,929	7,148
Stock-based compensation expense	(43,954)	(68,349)
Interest expense	(79,232)	(123,330)
Income (Loss) Before Income Taxes	$ (1,476,596)	$ 188,705

Note 17—Supplemental Oil and Gas Reserve Information (Unaudited)

Results of Operations for Oil, Natural Gas and NGL Producing Properties

The following are the results of operations (in thousands) of the Company's oil and gas producing activities, before corporate overhead and interest expenses. The Company assumed a statutory rate of 24.7% for the years ended December 31, 2019, 2018 and 2017.

	For the Year Ended December 31,		
	2019	2018	2017
Revenues	$ 905,374	$ 1,060,743	$ 604,296
Operating Expenses:			
Production expenses	218,576	209,169	162,673
Exploration and abandonment expenses	88,794	31,611	36,256
Depletion, depreciation, amortization and accretion	524,537	431,946	311,916
Impairment of proved properties	1,337,996	16,166	—
Results of operations before income tax benefit (expense)	(1,264,529)	371,851	93,451
Income tax benefit (expense)	312,339	(91,847)	(23,082)
Results of Operations	$ (952,190)	$ 280,004	$ 70,369

Oil, Natural Gas and NGL Reserve Quantities (Unaudited)

The reserves at December 31, 2019, 2018 and 2017 presented below were prepared by the independent engineering firm Ryder Scott Company, L.P. All reserves are located within the DJ Basin. Proved oil, natural gas and NGL reserves are the estimated quantities of oil, natural gas and NGL which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil, natural gas and NGL reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. The principal methodologies employed are decline curve analysis and analogy. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

The following table sets forth information for the years ended December 31, 2019, 2018 and 2017 with respect to changes in the Company's proved (i.e., proved developed and undeveloped) reserves:

	Crude Oil Mbbls	Natural Gas MMcf	NGL Mbbls	MBoe Total
Balance as of December 31, 2016	90,995	507,735	62,448	238,066
Revisions of previous estimates	(626)	9,350	1,962	2,894
Purchase of reserves	10,761	11,184	1,563	14,188
Extensions, discoveries, and other additions	19,738	130,295	15,034	56,488
Sale of reserves	—	—	—	—
Production	(9,593)	(32,395)	(3,901)	(18,894)
Balance as of December 31, 2017	111,275	626,169	77,106	292,742
Revisions of previous estimates	6,264	(49,239)	(1,383)	(3,325)
Purchase of reserves	6,296	24,668	3,264	13,672
Extensions, discoveries, and other additions	32,475	164,424	22,853	82,733
Sale of reserves	(5,786)	(15,907)	(1,730)	(10,167)
Production	(14,679)	(46,847)	(5,260)	(27,747)
Balance as of December 31, 2018	135,845	703,268	94,850	347,908
Revisions of previous estimates	(41,255)	(118,365)	(29,554)	(90,537)
Purchase of reserves	275	1,526	217	746
Extensions, discoveries, and other additions	14,620	72,880	8,425	35,191
Sale of reserves	(2,590)	(14,510)	(1,765)	(6,773)
Production	(15,436)	(64,710)	(6,164)	(32,386)
Balance as of December 31, 2019	91,459	580,089	66,009	254,149
Proved Developed Reserves, included above				
Balance as of December 31, 2017	37,078	222,236	27,932	102,049
Balance as of December 31, 2018	47,075	316,499	39,689	139,514
Balance as of December 31, 2019	45,807	350,309	39,001	143,193
Proved Undeveloped Reserves, included above				
Balance as of December 31, 2017	74,197	403,933	49,174	190,693
Balance as of December 31, 2018	88,771	386,769	55,162	208,395
Balance as of December 31, 2019	45,652	229,781	27,008	110,957

- The values for the 2019 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2019. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $55.69 per barrel (West Texas Intermediate price) for crude oil and NGL and $2.58 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2019 was $48.09 per barrel for oil, $1.04 per Mcf for natural gas and $13.87 per barrel for NGL.

- The values for the 2018 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2018. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $65.56 per barrel (West Texas Intermediate price) for crude oil and NGL and $3.10 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2018 was $57.65 per barrel for oil, $1.47 per Mcf for natural gas and $20.45 per barrel for NGL.

- The values for the 2017 oil, natural gas and NGL reserves are based on the 12-month arithmetic average of the first day of the month prices for the period from January through December 31, 2017. The unweighted arithmetic average first-day-of-month prices for the prior twelve months were $51.34 per barrel (West Texas Intermediate price) for crude oil and NGL and $2.98 per MMBtu (Henry Hub price) for natural gas. All prices are then further adjusted for transportation, quality and basis differentials. The average resulting price used as of December 31, 2017 was $42.89 per barrel for oil, $1.73 per Mcf for natural gas and $20.28 per barrel for NGL.

For the year ended December 31, 2019, the Company had downward revisions of previous estimates of 90,537 MBoe primarily due to revisions of PUD expirations due to the SEC's five year drilling rule caused by the change in business strategy to focus on being cash flow positive rather than maximizing reserves growth. As a result of ongoing drilling and completion activities during 2019, the Company reported extensions, discoveries, and other additions of 35,191 MBoe. Additionally, during 2019 the Company sold reserves of 6,773 MBoe and purchased reserves of 746 MBoe.

For the year ended December 31, 2018, the Company had upward revisions of previous estimates of 3,325 MBoe. As a result of ongoing drilling and completion activities during 2018, the Company reported extensions, discoveries, and other additions of 82,733 MBoe. Additionally, during 2018 the Company sold reserves of 10,167 MBoe and purchased reserves of 13,672 MBoe.

For the year ended December 31, 2017, the Company had downward revisions of previous estimates of 2,894 MBoe. As a result of ongoing drilling and completion activities during 2017, the Company reported extensions, discoveries, and other additions of 56,488 MBoe. Additionally, during 2017 the Company purchased reserves of 14,188 MBoe.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil, Natural Gas and NGL Reserves

The Company follows the guidelines prescribed in ASC 932, *Extractive Activities-Oil and Gas* for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil, natural gas and NGL reserve disclosures, standardized measures of discounted future net cash flows from proved oil, natural gas and NGL reserves and the reconciliations of standardized measures from year to year.

The information is based on estimates of proved reserves attributable to the Company’s interest in oil and gas properties as of December 31 of the years presented. These estimates were prepared by Ryder Scott Company L.P., independent petroleum engineers.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows: (1) Estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions. (2) The estimated future cash flows are compiled by applying the trailing twelve-month average of the first of the month prices applied to the Company’s proved reserve year-end quantities. (3) The future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred. (4) Future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company’s expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations, since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company’s oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following summary sets forth the Company’s future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure prescribed in ASC 932, *Extractive Activities-Oil and Gas* (in thousands):

	For the Year Ended December 31,		
	2019	2018	2017
Future crude oil, natural gas and NGL sales	$ 5,914,900	$ 10,805,063	$ 7,422,335
Future production costs	(2,166,852)	(3,215,840)	(2,227,370)
Future development costs	(798,225)	(1,912,641)	(1,662,859)
Future income tax expense	(7,647)	(694,398)	(212,923)
Future net cash flows	$ 2,942,176	$ 4,982,184	$ 3,319,183
10% annual discount	(1,038,303)	(2,082,201)	(1,440,177)
Standardized measure of discounted future net cash flows(1)	$ 1,903,873	$ 2,899,983	$ 1,879,006

(1) For the years ended December 31, 2019, 2018 and 2017, future income tax expenses in the Company’s calculation of the standardized measure of discounted future net cash flows are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and gas properties, other deductions, credit and allowances relating to the Company’s proved reserves. For purposes of the standardized measure calculation, it was assumed that all of the Company’s operations are attributable to the Company’s oil and gas assets.

The following are the principal sources of change in the standardized measure (in thousands):

	For the Year Ended December 31,		
	2019	2018	2017
Balance at beginning of period	$ 2,899,983	$ 1,879,006	$ 722,996
Sales of crude oil, natural gas and NGL, net	(681,667)	(851,574)	(441,623)
Net change in prices and production costs	(878,838)	902,762	586,271
Net change in future development costs	3,147	(174,112)	3,959
Extensions and discoveries	256,147	629,304	330,160
Acquisitions of reserves	9,623	88,124	59,745
Sale of reserves	(52,710)	(55,042)	—
Revisions of previous quantity estimates	(560,397)	132,373	188,421
Previously estimated development costs incurred	348,137	306,546	331,550
Net changes in income taxes	347,057	(253,044)	(79,181)
Accretion of discount	324,981	197,580	74,061
Changes in production timing and other	(111,590)	98,060	102,647
Balance at end of period	$ 1,903,873	$ 2,899,983	$ 1,879,006

Note 18—Unaudited Quarterly Financial Data

The following is a summary of the unaudited quarterly financial data for each of the quarters from first quarter 2018 through fourth quarter 2019 (in thousands, except per share data). Historical results are not necessarily indicative of the results to be expected in future periods. This data should be read together with the Company's consolidated financial statements and the related notes included elsewhere in this Annual Report:

	For The Three Months Ended			
	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019
Total Revenues	$ 221,917	$ 222,057	$ 176,942	$ 285,720
Operating Income(1)	52,796	49,647	22,334	36,488
Net Income (Loss)	(94,032)	43,444	33,924	(1,350,758)
Basic and Diluted Income (Loss) Per Common Share	(0.60)	0.22	0.17	(9.84)

	For The Three Months Ended			
	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
Total Revenues	$ 230,215	$ 260,196	$ 282,160	$ 288,172
Operating Income(1)	85,443	98,300	121,171	110,885
Net Income (Loss)	(51,995)	8,848	65,150	99,852
Basic Income (Loss) Per Common Share	(0.32)	0.03	0.33	0.52
Diluted Income (Loss) Per Common Share	(0.32)	0.03	0.33	0.51

(1) Total revenues less lease operating expenses, midstream operating expenses, transportation and gathering expenses, production taxes and depreciation, depletion, amortization and accretion expenses.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In accordance with the Exchange Act, Rules 13a-15(b) and 15d-15(b), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2019. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective as of December 31, 2019, due to the material weakness in internal control over financial reporting as described below.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with generally accepted accounting principles. 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.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2019, using the criteria established in *Internal Control-Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that our internal control over financial reporting was not effective as of December 31, 2019, due to the material weakness in internal control over financial reporting as described below.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Management determined that the Company did not design and maintain effective controls to determine the appropriate contract termination date and evaluate the potential accounting implications of changes in termination dates of contracts with customers. This material weakness resulted in a restatement of the Company's condensed consolidated financial statements as of and for the three and nine month periods ended September 30, 2019 and immaterial errors to the consolidated financial statements for the periods ended December 31, 2018, March 31, 2019 and June 30, 2019. The line items affected were oil revenue, accounts payable and accrued liabilities, other non-current liabilities, inventory, prepaid expenses and other, and other non-current assets. Additionally, this material weakness could result in a misstatement of the aforementioned financial statement line items or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2019 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears under Part II, Item 8 of this Annual Report.

Management's Material Weakness Remediation Plan

The Company and its Board of Directors are committed to maintaining a strong internal control environment. Management has evaluated the material weakness described above and developed a remediation plan to address the material weakness. The remediation plan includes additional procedures around determining the contract termination date pursuant to the accounting treatment under ASC 606 - Revenue from Contracts with Customers. Management is committed to successfully implementing the remediation plan and plans to commence the evaluation of its updated design of internal controls for implementation expeditiously.

Changes in Internal Control over Financial Reporting

Except for the remediation plan described immediately above, there were no additional changes in our system of internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information responsive to Items 401, 405, 406 and 407 of Regulation S-K to be included in our definitive Proxy Statement for our 2020 Annual Meeting of Shareholders, to be filed within 120 days of December 31, 2019, pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the "2020 Proxy Statement"), is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information responsive to Items 402 and 407 of Regulation S-K to be included in our 2020 Proxy Statement is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information responsive to Items 201(d) and 403 of Regulation S-K to be included in our 2020 Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information responsive to Items 404 and 407 of Regulation S-K to be included in our 2020 Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information responsive to Item 9(e) of Schedule 14A to be included in our 2020 Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed With This Report

1. FINANCIAL STATEMENTS

The following consolidated financial statements of the Company are filed as a part of this report:

2. FINANCIAL STATEMENT SCHEDULES

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements and related notes.

3. EXHIBITS

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below in the "Index to Exhibits" attached hereto and are incorporated herein by reference.

INDEX TO EXHIBITS

Exhibit Number	Description
**2.1	Agreement and Plan of Merger, dated October 17, 2016, by and between Extraction Oil & Gas, Inc. and Extraction Oil & Gas Holdings, LLC. (incorporated by reference to Exhibit 2.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.1	Certificate of Incorporation of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**3.2	Certificate of Designations of Series A Preferred Stock of Extraction Oil & Gas, Inc., filed with the Secretary of State of the State of Delaware on October 17, 2016 (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**3.3	Bylaws of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.2 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
**4.1	Amended and Restated Registration Rights Agreement, dated October 17, 2016, by and among Extraction Oil & Gas, Inc. and the other persons named therein (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.2	Registration Rights Agreement, dated October 3, 2016, by and among Extraction Oil & Gas, LLC, Extraction Oil & Gas Holdings, LLC and the other persons named therein (incorporated by reference to Exhibit 4.2 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
**4.3	Registration Rights Agreement, dated December 15, 2016, by and among Extraction Oil & Gas, Inc. and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on December 16, 2016).
**4.4	Indenture, dated August 1, 2017, by and between Extraction Oil & Gas, Inc. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on August 3, 2017).
**4.5	Indenture, dated as of January 25, 2018, by and among Extraction Oil & Gas, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 25, 2018).
*4.6	Description of Capital Stock.
†**10.1	Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (incorporated by reference to Exhibit 4.4 to the Company’s Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.2	Form of Restricted Stock Unit Award Agreement (for Employees) (incorporated by reference to Exhibit 4.5 to the Company’s Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.3	Form of Restricted Stock Unit Award Agreement (for Directors) (incorporated by reference to Exhibit 4.6 to the Company’s Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.4	Form of Stock Option Award Agreement (incorporated by reference to Exhibit 4.7 to the Company’s Registration Statement on Form S-8 (File No. 333-214089) filed with the Commission on October 13, 2016).
†**10.5	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Mark A. Erickson (incorporated by reference to Exhibit 10.4 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.6	Employment Agreement dated as of October 11, 2016 among the Company, XOG Services, LLC, and Matthew R. Owens (incorporated by reference to Exhibit 10.5 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†**10.7	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K (File No. 001-37907) filed with the Commission on February 27, 2018).
†**10.8	Indemnification Agreement (Audrey Robertson) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on September 19, 2019).

†**10.9	Amended and Restated Employment Agreement effective as of November 1, 2016 among the Company and Tom L. Brock (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on November 22, 2016).
†**10.10	Employment Agreement effective as of November 7, 2016 among the Company and Eric J. Christ (incorporated by reference to Exhibit 10.11 to the Company's Annual Report on Form 10-K (File No. 001-37907) filed with the Commission on February 27, 2018).
†**10.11	Amendment to Employment Agreement effective as of February 17, 2017 among the Company and Eric J. Christ (incorporated by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K (File No. 001-37907) filed with the Commission on February 27, 2018).
**10.12	Amended and Restated Credit Agreement, dated as of August 16, 2017, by and between Extraction Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on August 21, 2017).
**10.13	Increase Agreement, Joinder and Amendment No. 1 to Amended and Restated Credit Agreement, dated as of October 11, 2017, by and between Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of the Company, as guarantors, Wells Fargo Bank, National Association, as administrative agent and issuing lender and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 13, 2017).
**10.14	Master Assignment, Increase Agreement and Amendment No.2 to Amended and Restated Credit Agreement, dated as of January 5, 2018, by and between Extraction Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 9, 2018).
**10.15	Consent Agreement and Amendment No. 3 to Amended and Restated Credit Agreement, dated as of February 27, 2018, by and between Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of the Company, as guarantors, Wells Fargo Bank, National Association, as administrative agent and issuing lender and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 2, 2018).
**10.16	Amendment No. 4 to Amended and Restated Credit Agreement, dated as of May 23, 2018, by and between Extraction Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on May 29, 2018).
**10.17	Consent and Amendment No. 5 to Amended and Restated Credit Agreement, dated as of October 2, 2018, by and among Extraction Oil & Gas, Inc., as borrower, certain of its subsidiaries, as guarantors, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 9, 2018).
**10.18	Borrowing Base Increase Agreement, dated as of December 20, 2018, among Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of Extraction Oil & Gas, Inc., as guarantors, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on December 26, 2018).
**10.19	Consent and Amendment No. 6 to Amended and Restated Credit Agreement, dated as of January 8, 2019, by and among Extraction Oil & Gas, Inc., as borrower, certain of its subsidiaries, as guarantors, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 14, 2019).
**10.20	Master Assignment and Amendment No. 7 to Amended and Restated Credit Agreement, dated as of June 27, 2019, by and among Extraction Oil & Gas, Inc., as borrower, certain of its subsidiaries, as guarantors, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on July 1, 2019).
**10.21	Amendment No. 8 to Amended and Restated Credit Agreement, dated as of August 28, 2019, by and among Extraction Oil & Gas, Inc., as borrower, certain of its subsidiaries, as guarantors, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent and issuing lender (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (File No. 001-37907) filed with the Commission on August 30, 2019).

**10.22	Borrowing Base Decrease Agreement, dated as of November 4, 2019, among Extraction Oil & Gas, Inc., as borrower, certain subsidiaries of Extraction Oil & Gas, Inc., as guarantors, the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on November 7, 2019).
*21.1	Subsidiaries of the Registrant
*23.1	Consent of PricewaterhouseCoopers LLP
*23.2	Consent of Ryder Scott Company, L.P.
*31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Report of Ryder Scott Company, L.P.
*101	Interactive Data Files

† Management contract or compensatory plan or agreement.
* Filed herewith.
** Previously filed.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements 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.

Date: March 12, 2020.

Extraction Oil & Gas, Inc.

By: /s/ MATTHEW R. OWENS
Matthew R. Owens
President and Chief Executive Officer

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

/s/ MATTHEW R. OWENS Matthew R. Owens	President, Chief Executive Officer and Director (Principal Executive Officer)	March 12, 2020
/s/ TOM L. BROCK Tom L. Brock	Vice President, Chief Accounting Officer (Principal Accounting Officer and Principal Financial Officer)	March 12, 2020
Thomas B. Tyree Jr.	Director	March 12, 2020
/s/ JOHN S. GAENSBAUER John S. Gaensbauer	Director	March 12, 2020
/s/ PETER A. LEIDEL Peter A. Leidel	Director	March 12, 2020
/s/ MARVIN M. CHRONISTER Marvin M. Chronister	Director	March 12, 2020
/s/ PATRICK D. O’BRIEN Patrick D. O’Brien	Director	March 12, 2020
/s/ WAYNE W. MURDY Wayne W. Murdy	Director	March 12, 2020
/s/ AUDREY ROBERTSON Audrey Robertson	Director	March 12, 2020

Exhibit 4.6

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

Throughout this exhibit, references to the "Company," "we," "our," and "us" refer to Extraction Oil & Gas, Inc. The following summary of terms of our common stock, $0.01 par value per share (the "common stock") is based upon our amended and restated certificate of incorporation (the "certificate of incorporation") and bylaws (the "bylaws"). This summary is not complete and is subject to, and qualified in its entirety by reference to, the certificate of incorporation and bylaws. For a complete description of the terms and provisions of the common stock, refer to the certificate of incorporation and bylaws, which are filed as exhibits to our Annual Report on Form 10-K. We encourage you to read these documents and the applicable portion of the Delaware General Corporation Law, as amended (the "DGCL"), carefully.

Common Stock

Our authorized capital stock consists of 900,000,000 shares of common stock and 50,000,000 shares of preferred stock, $0.01 par value per share.

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock are not entitled to vote on any amendment to the certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the DGCL. Subject to prior rights and preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably in proportion to the shares of common stock held by them such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange, preemption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets in proportion to the shares of common stock held by then that are remaining after payment or provision for payment of all of our debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

Anti-Takeover Effects of Provisions of Our Certificate of Incorporation, our Bylaws and Delaware Law

Some provisions of Delaware law, our certificate of incorporation and our bylaws contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise; or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

Section 203 of the DGCL prohibits a Delaware corporation, including those whose securities are listed for trading on the NASDAQ, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

We have elected to not be subject to the provisions of Section 203 of the DGCL.

Certificate of Incorporation and Bylaws

Provisions of our certificate of incorporation and bylaws may delay or discourage transactions involving an actual or potential change in control or change in our management, including transactions in which stockholders might otherwise receive a premium for their shares, or transactions that our stockholders might otherwise deem to be in their best interests. Therefore, these provisions could adversely affect the price of our common stock.

Among other things, our certificate of incorporation and bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our bylaws specify the requirements as to form and content of all stockholders' notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;
- provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;
- provide that subject to the rights of the holders of any series of preferred stock to elect directors under specified circumstances, the authorized number of directors may be changed only by resolution of the board of directors;
- provide that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;
- provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock with respect to such series;

- provide our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of at least two-thirds of our then outstanding common stock;

- provide that special meetings of our stockholders may only be called by the board of directors (pursuant to a resolution adopted by a majority of the board), the chief executive officer or the chairman of the board;

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

- provide that we renounce any interest in the business opportunities of (i) Yorktown or any of its officers, directors, employees, partners, affiliates and (ii) any portfolio company in which such entities or persons have an equity interest (other than us and our subsidiaries) (other than our directors that are presented business opportunities in their capacity as our directors) and that they have no obligation to offer us those investments or opportunities; and

- provide that our bylaws can be amended or repealed at any regular or special meeting of stockholders or by the board of directors.

Forum Selection

Our certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for:

- any derivative action or proceeding brought on our behalf;

- any action asserting a claim for a breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders;

- any action asserting a claim against us arising pursuant to any provision of the DGCL, our certificate of incorporation or our bylaws; or

- any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein.

Our certificate of incorporation also provides that any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of and to have consented to this forum selection provision. However, it is possible that a court could find our forum selection provision to be inapplicable or unenforceable.

The choice of forum provisions summarized above are not intended to apply to claims for which federal law creates exclusive jurisdiction, including the Exchange Act. We further note that the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created under the Securities Act, so there is uncertainty as to whether a court would enforce the forum selection provision with respect to claims under the Securities Act, and in any event, our stockholders cannot waive compliance with federal securities laws and the rules and regulations thereunder. Stockholders may be subject to increased costs to bring these claims, and choice of forum provisions could have the effect of discouraging claims or limiting investors' ability to bring claims in a judicial forum that they find favorable.

List of Subsidiaries of Extraction Oil & Gas, Inc.

Name of Subsidiary	Jurisdiction of Incorporation or Organization
7N, LLC	Delaware
8 North, LLC	Delaware
Bison Exploration, LLC	Delaware
Elevation Midstream, LLC	Delaware
Extraction Finance Corp.	Delaware
Mountaintop Minerals, LLC	Delaware
Table Mountain Resources, LLC	Delaware
XOG Services, Inc.	Colorado
XOG Services, LLC	Delaware
XTR Midstream, LLC	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-229767 and No. 333-228202) and Form S-8 (No. 333-214089 and No. 333-232943) of Extraction Oil & Gas, Inc. of our report dated March 12, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
March 12, 2020

EXHIBIT 23.2

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

FAX (303) 623-4258

621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303)623-9147

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our report letter dated February 5, 2020, included in the Annual Report on Form 10-K of Extraction Oil & Gas, Inc. (the "Company"). We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and of our report letter dated February 5, 2020, into the Company’s registration statements on (i) Form S-8 (File No. 333-214089 and 333-232943), including any amendments thereto and (ii) on Form S-3 (File Nos. 333-229767 and 333-228202), as amended and including any further amendments thereto, in accordance with the requirements of the Securities Act of 1933, as amended.

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

Denver, Colorado
March 12, 2020

EXHIBIT 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 7241**

I, Matthew R. Owens, certify that:

1. I have reviewed this Annual Report on Form 10-K (this "Report") of Extraction Oil & Gas, Inc. (the "Registrant");

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 period 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(s) 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(s) 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 12, 2020

/S/ MATTHEW R. OWENS

Matthew R. Owens
President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 7241**

I, Tom L. Brock, certify that:

1. I have reviewed this Annual Report on Form 10-K (this "Report") of Extraction Oil & Gas, Inc. (the "Registrant");

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 period 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(s) 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(s) 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 12, 2020

/S/ TOM L. BROCK

Tom L. Brock
Vice President and Chief Accounting Officer
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the Annual Report on Form 10-K for the year ended December 31, 2019 of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Matthew R. Owens, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 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, as amended; 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 12, 2020

/S/ MATTHEW R. OWENS

Matthew R. Owens
President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 32.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER
UNDER SECTION 906 OF THE
SARBANES OXLEY ACT OF 2002, 18 U.S.C. § 1350

In connection with the Annual Report on Form 10-K for the year ended December 31, 2019 of Extraction Oil & Gas, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Tom L. Brock, Vice President and Chief Accounting Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 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, as amended; 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 12, 2020

/S/ TOM L. BROCK

Tom L. Brock
Vice President and Chief Accounting Officer
(Principal Financial Officer)

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293
FAX (303) 623-4258
TELEPHONE (303) 623-9147

February 5, 2020

Extraction Oil & Gas, Inc.
370 17th Street, Suite 5300
Denver, Colorado 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Extraction Oil & Gas, Inc. (Extraction) as of December 31, 2019. The subject properties are located in the state of Colorado. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 5, 2020 and presented herein, was prepared for public disclosure by Extraction in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. This report contains adjustments to natural gas liquids revenue calculations by Extraction on February 5, 2020. This report shall supersede all previous reports for net reserves and income data as of December 31, 2019.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Extraction as of December 31, 2019.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Extraction Oil & Gas, Inc.
As of December 31, 2019

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – MBarrels	44,456	1,351	45,652	91,459
Plant Products – MBarrels	38,067	933	27,008	66,008
Gas – MMcf	341,905	8,403	229,781	580,089
Income Data ($M)				
Future Gross Revenue	$3,056,766	$88,353	$2,769,780	$5,914,899
Deductions	1,277,718	35,189	1,652,169	2,965,076
Future Net Income (FNI)	$1,779,048	$53,164	$1,117,611	$2,949,823
Discounted FNI @ 10%	$1,300,457	$38,284	$ 567,911	$1,906,652

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

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

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

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

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

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2019 Total Proved
9	$1,975,837
12	$1,782,443
15	$1,625,036
20	$1,419,213

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

Reserves Included in This Report

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

The various reserves status categories are defined under the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of wells shut-in due to gas pipeline constraints or offset completion activity.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

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

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

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

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

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

Estimates of Reserves

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

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

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

The proved reserves for the properties included herein were estimated by performance methods or analogy. Approximately one hundred percent of the proved producing and proved non-producing reserves were estimated by performance methods. These performance methods include decline curve analysis, which utilized extrapolations of historical production data available through December 2019 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Extraction and were considered sufficient for the purpose thereof.

Approximately one hundred percent of the proved undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were considered sufficient for the purpose thereof.

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

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

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to

Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

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

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

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

Hydrocarbon Prices

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

Extraction furnished us with the above mentioned average prices in effect on December 31, 2019. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

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

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

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$55.69/bbl	$48.09/bbl
	NGLs	WTI Cushing	$55.69/bbl	$13.87/bbl
	Gas	Henry Hub	$2.58/MMBTU	$1.04/Mcf

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

Costs

Operating costs for the leases and wells in this report were furnished by Extraction and are based on the operating expense reports of Extraction and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For Extraction operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-Extraction-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Extraction. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Extraction and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Extraction were accepted without independent verification.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Extraction’s plans to develop these reserves as of December 31, 2019. The implementation of Extraction’s development plans as presented to us and incorporated herein is subject to the approval process adopted by Extraction’s management. As the result of our inquiries during the course of preparing this report, Extraction has informed us that the development activities included herein have been subjected to and received the internal approvals required by Extraction’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Extraction. Extraction has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Extraction has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

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

Standards of Independence and Professional Qualification

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

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

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

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

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

Terms of Usage

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

Extraction makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Extraction has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of Extraction, of the references to our name, as well as to the references to our third party report for Extraction, which appears in the December 31, 2019 annual report on Form 10-K of Extraction. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Extraction.

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

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

Very truly yours,

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

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President
[SEAL]

/s/ Edward M. Polishuk

Edward M. Polishuk
Senior Petroleum Evaluator

SEG-EMP (DCR)/pl

Professional Qualifications of Primary Technical Person

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

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is also a member of the Society of Petroleum Engineers and a former chairman for the Denver Chapter of the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2019 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference in Houston, Texas which covered a variety of reserves topics including data analytics, unconventional resource issues, SEC comment letter trends, and others. In addition, Mr. Gardner attended the 2019 SPEE conference held at Lake Louise, Alberta, Canada, various local SPEE technical seminars, URTeC, and other internal company training courses throughout the year covering topics such as analysis techniques for unconventional reservoirs, ethics, regulatory issues, reserves evaluation, and more.

Based on his educational background, professional training and more than 14 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.