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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2019

☐ **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 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

Texas	Trading Symbol(s)	**95-4079863**
(State or other jurisdiction of incorporation or organization)	MCF	(IRS Employer Identification No.)

717 Texas Avenue, Suite 2900
Houston, Texas 77002
(Address of principal executive offices)

(713) 236-7400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, Par Value $0.04 per share	NYSE American

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

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

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

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

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

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

At June 28, 2019, the aggregate market value of the registrant's common stock held by non-affiliates (based upon the closing sale price of shares of such common stock as reported on the NYSE American) was $47.2 million. As of March 23, 2020, there were 129,122,673 shares of the registrant's common stock outstanding.

Documents Incorporated by Reference

Items 10, 11, 12, 13 and 14 of Part III have been omitted from this report since the registrant will file with the Securities and Exchange Commission, not later than 120 days after the close of its fiscal year, a definitive proxy statement, pursuant to Regulation 14A. The information required by Items 10, 11, 12, 13 and 14 of this report, which will appear in the definitive proxy statement, is incorporated by reference into this Form 10-K.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED DECEMBER 31, 2019
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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Certain statements contained in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases "should", "could", "may", "will", "believe", "plan", "intend", "expect", "potential", "possible", "anticipate", "estimate", "forecast", "view", "efforts", "goal" and similar expressions identify forward-looking statements and express our expectations about future events. Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties that could cause or contribute to such differences include, without limitation, those discussed in the section entitled "Risk Factors" included in this report and those factors summarized below:

- volatility and significant declines in natural gas, natural gas liquids and oil prices, including regional differentials;
- any reduction in our borrowing base from time to time;
- our ability to successfully develop our undeveloped acreage positions in the Southern Delaware Basin and the Mid-continent area of Oklahoma, and realize the benefits associated therewith;
- increased cost risks associated with our exploration and development in the Gulf of Mexico;
- our financial position;
- our business strategy, including execution of any changes in our strategy;
- meeting our forecasts and budgets, including our 2020 capital expenditure budget;
- expectations regarding natural gas and oil markets in the United States and our realized prices;
- operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and natural gas processing facilities;
- the risks associated with acting as operator of deep high pressure and high temperature wells, including well blowouts and explosions, onshore and offshore;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which we have made a large capital commitment relative to the size of our capitalization structure;
- the timing and successful drilling and completion of natural gas and oil wells;
- the concentration of drilling in the Southern Delaware Basin, including lower than expected production attributable to down spacing of wells;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations, fund our drilling program and support our acquisition efforts;
- the cost and availability of rigs and other materials, services and operating equipment;
- timely and full receipt of sales proceeds from the sale of our production;
- our ability to find, acquire, market, develop and produce new natural gas and oil properties;
- the conditions of the capital markets and our ability to access debt and equity capital markets or other non-bank sources of financing;
- actions by current and potential sources of capital, including lenders;

- interest rate volatility;
- our ability to successfully integrate the businesses, properties and assets we acquire, including those in new areas of operation;
- our ability to complete strategic dispositions or acquisitions of assets or businesses and realize the benefits of such dispositions or acquisitions;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- the need to take impairments on our properties due to lower commodity prices;
- the ability to post additional collateral for current bonds or comply with new supplemental bonding requirements imposed by the Bureau of Ocean Energy Management;
- operating hazards attendant to the natural gas and oil business including weather, environmental risks, accidental spills, blowouts and pipeline ruptures and other risks;
- downhole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps;
- actions or inactions of third-party operators of our properties;
- actions or inactions of third-party operators of pipelines or processing facilities;
- the ability to retain key members of senior management and key technical employees and to find and retain skilled personnel;
- strength and financial resources of competitors;
- federal and state legislative and regulatory developments and approvals (including additional taxes and changes in environmental regulations);
- the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") and other oil exporting nations to agree to and maintain oil price and production controls;
- the uncertain impact of supply of and demand for oil, natural gas and NGLs;
- our ability to obtain goods and services critical to the operation of our properties;
- worldwide and United States economic conditions;
- outbreaks and pandemics, even outside our areas of operation, including COVID-19;
- the ability to construct and operate infrastructure, including pipeline and production facilities;
- the continued compliance by us with various pipeline and gas processing plant specifications for the gas and condensate produced by us;
- operating costs, production rates and ultimate reserve recoveries of our natural gas and oil discoveries;
- expanded rigorous monitoring and testing requirements;
- the ability to obtain adequate insurance coverage on commercially reasonable terms; and
- the limited trading volume of our common stock and general trading market volatility.

Any of these factors and other factors described in this report could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable when made, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. You should not place undue reliance on forward-looking statements in this report as they speak only as of the date of this report.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas and natural gas liquids 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 natural gas liquids that are ultimately recovered.

All forward-looking statements, expressed or implied, in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or any person acting on our behalf may issue.

We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

All references in this Form 10-K to the "Company", "Contango", "we", "us" or "our" are to Contango Oil & Gas Company and its wholly-owned subsidiaries. Unless otherwise noted, all information in this Form 10-K relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves is based on estimates prepared by independent engineers, and is net to our interest.

PART I

Item 1. *Business*

Overview

We are a Houston, Texas based independent oil and natural gas company, with regional offices in Oklahoma City and Stillwater, Oklahoma. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore Texas, Oklahoma, Louisiana and Wyoming properties and use that cash flow to explore, develop, exploit and acquire oil and natural gas properties across the United States. We were originally formed in 1999 as a Nevada corporation and changed our state of incorporation to the State of Delaware in 2000. On June 14, 2019, following approval by our stockholders at the 2019 annual meeting of stockholders, we changed our state of incorporation from the State of Delaware to the State of Texas.

In December 2019, we entered into a Joint Development Agreement with Juneau Oil & Gas, LLC ("Juneau"), which provides us the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. See Note 4 – "Acquisitions and Dispositions" for more information.

In September 2019, we entered into unrelated purchase agreements with Will Energy Corporation ("Will Energy") and White Star Petroleum, LLC and certain of its affiliates (collectively, "White Star") to purchase certain producing assets and undeveloped acreage, primarily in Oklahoma. These transactions closed during the three months ended December 31, 2019. See Note 4 – "Acquisitions and Dispositions" for more information.

The following table lists our primary producing areas as of December 31, 2019:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Mid-continent Region of Oklahoma	Mississippian, Woodford, Oswego, Cottage Grove, Chester and Red Fork
Southern Delaware Basin, Pecos County, Texas	Wolfcamp A and B
Madison and Grimes counties, Texas	Woodbine / Upper Lewisville
Zavala and Dimmit counties, Texas	Buda / Eagle Ford / Georgetown
San Augustine County, Texas	Haynesville shale, Mid Bossier shale and James Lime
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Weston County, Wyoming	Muddy Sandstone
Sublette County, Wyoming	Jonah Field [(1)]

(1) Through a 37% equity investment in Exaro Energy III LLC ("Exaro"). Production from this investment is not included in our reported production results or in our reported reserves for any periods reported herein.

From our initial entry into the Southern Delaware Basin in 2016 and through early 2019, we focused on the development of our initial 6,500 net acre position in Pecos County, Texas ("Bullseye"), and in December 2018, we purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of our Bullseye acreage ("NE Bullseye") for approximately $7.5 million. We paid $3.2 million cash in December 2018, with the remaining cash balance paid in installments in March and October of 2019. Our 2019 drilling program included the completion of one well previously drilled in the Bullseye area, the drilling and completion of a second Bullseye well, and the drilling and completion of three wells in the NE Bullseye area. As of December 31, 2019, we were producing from seventeen wells over our approximate 18,600 gross (8,000 net) acre position in West Texas, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. In December 2019, we began completion operations on the fourth NE Bullseye well, which began producing in January 2020. Also in December 2019, we completed and brought on production a Garfield County, Oklahoma well in our Central Oklahoma region, which we acquired in connection with the White Star acquisition. See Note 4 – "Acquisitions and Dispositions" for more information.

In response to low commodity prices and a related window of opportunity to acquire producing properties on very attractive terms, we finished our 2019 drilling program, which was designed to only preserve core areas of our West Texas play, and thereafter focused on identifying, evaluating and acquiring producing reserves. As a result, we were successful in closing the Will Energy and White Star acquisitions in the fourth quarter of 2019. For 2020, we believe that a continuing low price environment and a shortage of capital available to the industry may present more opportunities to acquire additional producing properties that could provide strong production, cash flow and future development potential at attractive rates of return. We plan to be active in pursuing such acquisition opportunities and then allowing our technical teams to leverage our experience and expertise to work on increasing returns through production enhancement, cost reduction and future development of the unproved drilling locations that come with the production acquired. We can provide no assurances that we will acquire any producing property opportunities on attractive terms, or at all, or that we will realize the expected benefits of any acquisition. We currently plan to limit our 2020 drilling program to only address leasehold commitments and preserve core acreage in our existing areas, while complementing that strategy with one to two relatively low cost, high-potential offshore exploratory wells on prospects recently acquired from Juneau. See Note 4 – "Acquisitions and Dispositions" for more information. We will continue to make balance sheet strength a priority in 2020 as we utilize excess cash flow to reduce debt and increase our capacity to quickly react to acquisition opportunities.

We are also currently undertaking an extensive review of all of our producing areas in light of the commodity price environment, and where determined justified and operationally feasible, we plan to potentially shut in or curtail unhedged production. Because of our low debt profile and borrowing cost of capital, we believe we may be able to temporarily shut in or curtail higher cost production when there is a decline in the commodity markets. We are also currently re-evaluating the economic justification for proceeding with the production-enhancing workover program originally scheduled for the first half of 2020. The limited onshore development drilling we planned for 2020 is also being re-evaluated.

As we focus on the above stated initiatives, we also continue to sell non-core assets to improve overall margins, to provide incremental liquidity, to reduce future asset retirement obligations and to improve our balance sheet. During the year ended 2018, we sold certain Eagle Ford Shale assets in Karnes County, Texas for $21.0 million; Gulf Coast conventional assets in Southeast Texas for $6.0 million, and Gulf Coast conventional and unconventional assets in South Texas for $0.9 million. In December 2018, we also sold our offshore Vermilion 170 property in exchange for a retained overriding royalty interest ("ORRI") in the well, the buyer's assumption of the plugging and abandonment obligation and an ORRI in any future wells drilled by the buyer on two nearby prospects that would produce through this platform. During the year ended 2019, we sold minor, non-core operated assets located in Lavaca and Wharton counties, Texas and Frio and Zavala counties, Texas, both of which sales were in exchange for the buyers' assumption of the plugging and abandonment liabilities of the properties. We recorded a gain of $0.6 million after removal of the asset retirement obligations associated with these properties sold in 2019.

In November 2018, we completed an underwritten public offering of 8,596,068 shares of our common stock for net proceeds of approximately $33.0 million, which were used to reduce borrowings under our former credit facility, fund the initial purchase of the NE Bullseye acreage and provide funding for our 2019 capital expenditure program.

In September 2019, we completed an underwritten public offering (the "September Public Offering") of 51,447,368 shares of common stock (of which 5,524,498 were reissued treasury shares) for net proceeds of approximately $46.2 million, after deducting the underwriting discount and fees and expenses. Net proceeds from the September Public Offering and concurrent Series A Private Placement (as defined below) were used to fund the cash portion of the purchase price for the Will Energy acquisition and to reduce borrowings under our former revolving credit facility.

In conjunction with the September Public Offering, we also entered into a purchase agreement with affiliates of John C. Goff, a director and significant shareholder, and current chairman, of the Company, to issue and sell in a private placement (the "Series A Private Placement") 789,474 shares of Series A contingent convertible preferred stock, which resulted in net proceeds of approximately $7.5 million.

In November 2019, we completed a private placement of 1,102,838 shares of Series B contingent convertible preferred stock, which resulted in net proceeds of approximately $21.0 million (the "Series B Private Placement"). Net proceeds from the Series B Private Placement were used to fund a portion of the purchase price and related transaction expenses for the White Star acquisition.

In the fourth quarter of 2019, we obtained approval from the holders of a majority of the voting power of the Company's capital stock to increase the number of common shares authorized for issuance from 100 million to 200 million common shares, at which time the Series A preferred shares automatically converted into 7,894,740 shares of common stock, the Series B preferred shares automatically converted into 11,028,380 shares of common stock, and the outstanding preferred shares were cancelled.

In December 2019, we also completed a private placement offering (the "December Offering") of 19,000,000 shares of common stock for net proceeds of approximately $45.7 million, after deducting the underwriting discount and fees and expenses. In conjunction with the December Offering, we also completed a private placement of 2,340,000 shares of Series C contingent convertible preferred stock (the "Series C Private Placement") with affiliates of Mr. Goff, Mr. Wilkie S. Colyer, Jr., our chief executive officer, and others, which resulted in net proceeds of approximately $5.6 million. An additional 360,000 Series C contingent convertible preferred shares were issued in a private placement to the placement agents for the December Offering and Series C Private Placement, as partial consideration for their services. Net proceeds from the December Offering and Series C Private Placement will be used for general corporate purposes, including capital expenditures under our Joint Development Agreement with Juneau. See Note 4 – "Acquisitions and Dispositions" for more information.

The Series C preferred shares are a new class of equity security that ranks equal to the common shares with respect to dividend rights and rights upon liquidation. The Series C preferred shares have no voting rights. Upon approval by the holders of a majority of the voting power of the Company's capital stock, each Series C preferred share will convert into one common share and, upon conversion, the outstanding Series C preferred shares will be cancelled.

Our production for the year ended December 31, 2019 was approximately 17.9 Bcfe (or 49.2 Mmcfe/d) and was composed of 41% from our offshore properties and 53% natural gas. Our production for the three months ended December 31, 2019 was approximately 8.7 Bcfe (or 94.2 Mmcfe/d), with 20% from our offshore properties and 48% natural gas. The production rates for the fourth quarter include November and December 2019 production from the acquired White Star and Will Energy properties in the Western Anadarko, Central Oklahoma and Other Onshore regions. See Note 4 – "Acquisitions and Dispositions" for more information.

As of December 31, 2019, our proved reserves, as estimated by William M. Cobb and Associates ("Cobb"), our independent petroleum engineering firm, in accordance with reserve reporting guidelines required by the Securities and Exchange Commission ("SEC"), were approximately 316.4 Bcfe, consisting of 131.3 Bcf of natural gas, 19.1 MMBbl of oil and condensate and 11.8 MMBbl of natural gas liquids ("NGLs"). As of December 31, 2019, our proved reserves were approximately 77% proved developed (volumetrically), approximately 89% of total volumes onshore and approximately 94% of total volumes attributed to wells and properties operated by us.

As of December 31, 2019, our proved reserves had a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $257.8 million and a present value, discounted at a 10% rate based on year-end SEC pricing guidelines (PV-10), of $286.6 million. PV-10 as of December 31, 2019 was based on SEC prices of $55.69 per barrel of oil and $2.52 per Mmbtu of natural gas. Resulting realized prices, after adjustments and differentials across all assets, were $2.17 per MMbtu of natural gas, $53.98 per barrel of oil and $16.95 per barrel of NGLs. As of December 31, 2019, our proved reserves were approximately 92% of total PV-10 proved developed, approximately 85% of total PV-10 onshore and approximately 93% of total PV-10 attributed to wells and properties operated by us. PV-10 is not an accounting principle generally accepted in the United States of America ("GAAP") and is therefore classified as a non-GAAP financial measure. A reconciliation of our Standardized Measure to PV-10 is provided under "Item 2. Properties - PV-10".

The following summary table sets forth certain information with respect to our proved reserves as of December 31, 2019 (excluding proved reserves attributable to our 37% equity investment in Exaro), as estimated by Cobb, and our net average daily production for the year ended December 31, 2019:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Offshore GOM	34.5	3 %	80 %	17 %	100 %	20.3
Central Oklahoma	133.5	26 %	42 %	32 %	97 %	12.2
Western Anadarko	47.1	15 %	61 %	24 %	98 %	2.6
West Texas	43.3	75 %	10 %	15 %	36 %	6.4
Other Onshore [1]	58.0	67 %	23 %	10 %	32 %	7.7
Total	316.4					49.2

(1) Includes areas in East, South and Southeast Texas, Louisiana, Wyoming and Mississippi.

The following summary table sets forth certain information with respect to the proved reserves attributable to our equity method investment in Exaro, as of December 31, 2019, as estimated by W.D. Von Gonten and Associates ("Von Gonten"), and our net share of Exaro's average daily production for the year ended December 31, 2019:

Region	Estimated Proved Reserves (Bcfe)	% Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Investment in Exaro	23.0	6 %	94 %	— %	100 %	18.2

Our Strategy

Our long-term business strategy is:

• *Pursuing accretive, opportunistic acquisitions that meet our strategic and financial objectives.* We believe that there is currently a window of opportunity for us to acquire PDP-heavy assets that also possess sizable undeveloped acreage positions from distressed and/or motivated sellers at an attractive discount to PDP PV-10 valuations. Consequently, we currently intend to focus our growth efforts on identifying, evaluating and pursuing the acquisition of such oil and natural gas properties in areas where we currently have a presence and/or specific operating expertise that will position us to enhance our expected acquisition returns through leveraging our operational experience and expertise in order to provide productivity and cost improvements, and where appropriate, increase reserves through development drilling. We may acquire individual properties or private or publicly traded companies, in each case for cash, common stock, preferred stock or a combination thereof. We believe that the ongoing low commodity price environment, and very limited sources of debt and/or equity capital available to our industry, should provide significant reserve and cash flow growth opportunity for us through potential corporate combinations that provide an attractive mix of significant cash flow and undeveloped growth potential.

• *Enhancing our existing portfolio by dedicating the majority of our drilling capital to our existing portfolio of oil and liquids-rich opportunities*. A key element of our long term strategy is to continue to develop the oil and natural gas liquids resource potential that we believe exists in numerous formations within our various oil/liquids weighted resource plays, and where possible, to expand our presence in those plays. Due to the current superior economics of oil production, as compared to natural gas, we expect to focus on oil and liquids-weighted opportunities as we strive to transition from a heavily weighted natural gas production profile to a more balanced reserve and production profile between oil/liquids and natural gas. In response to the low commodity price environment, and the current opportunity to be an asset consolidator in the industry, we plan to limit near-term drilling capital for the foreseeable future to that necessary to fulfill leasehold commitments, preserve core acreage, and where the opportunity exists, to drill where we can add production and cash flow at attractive rates of return. We will, however, continue to evaluate high quality drilling opportunities that have the potential to add significant reserves and cash flow to our portfolio at low finding and development cost, thereby providing returns superior to those generated in the currently active unconventional resource plays.

• *2020 business strategy.* During 2020, we intend to continue to minimize our drilling program and pursue growth through the acquisition of PDP-heavy assets, and use excess cash flow for the reduction in borrowings outstanding under our Credit Agreement. We plan to complement that conservative drilling program on our core onshore resource plays with one to two relatively low cost, but high potential, exploratory tests of prospects that we acquired from Juneau in December of 2019. We will also be keenly focused on reducing lease operating costs and general and administrative expenses, and improving cash margins and lowering our exposure to asset retirement obligations through the possible sale of additional non-core properties. We will continue to make balance sheet strength a priority in 2020 and will continue to evaluate certain acquisition opportunities that may arise in this low price environment. We retain the flexibility to be more aggressive in our drilling plans should planned results exceed expectations, should commodity prices improve, and/or we continue to show progress in reducing our drilling and completion costs, thereby making an expansion of our drilling program an appropriate business decision. Our 2020 capital expenditure budget is currently estimated at approximately $13.1 million and is expected to include the following:

- Offshore GOM: the Iron Flea prospect in the Grand Isle Block 45/46 area in the shallow waters off of the Louisiana coast will require $6.3 million to drill and $0.8 million to abandon in the case of dry hole. We expect that capital expenditures will exceed this amount if the prospect is a success due to evaluation and completions costs and the possibility of a second well and /or facilities.
- West Texas: $3.3 million to drill and complete one salt water disposal well and $0.4 million for infrastructure costs in our NE Bullseye area.
- Central Oklahoma: $2.3 million to complete three previously drilled wells, which we acquired from White Star.

We may revise our 2020 capital expenditure budget if deemed appropriate in light of changes in commodity prices or economic conditions.

Properties

Offshore Gulf of Mexico

As of December 31, 2019, our offshore assets consisted of five producing federal and two producing state of Louisiana company-operated wells in the shallow waters of the GOM. The following summary table sets forth certain information with respect to our offshore reserves as of December 31, 2019 and average daily offshore production for the year ended December 31, 2019:

Field	Estimated Proved Reserves (Bcfe)	% Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Dutch and Mary Rose	34.5	3 %	80 %	17 %	100 %	20.3
Total	34.5					20.3

Dutch and Mary Rose Field

We currently operate five producing wells located in federal waters at Eugene Island 10 (“Dutch”), and two producing wells located in adjacent Louisiana state waters (“Mary Rose”). We plugged and abandoned the Mary Rose #4 well in 2018 and the Mary Rose #5 well in 2019. We plan to plug the Mary Rose #3 well in 2020. All Dutch and Mary Rose wells flow to a Company-owned and operated production platform at Eugene Island 11. While we do not own the lease for the Eugene Island 11 block, this does not impact our ability to operate our facilities located on that block. Operators in the GOM may place platforms and facilities on any location without having to own the lease, provided that permission and proper permits from the Bureau of Safety and Environmental Enforcement (“BSEE”) have been obtained. We have obtained such permission and permits. We installed our facilities at Eugene Island 11 because that was the optimal gathering location in proximity to our wells and marketing pipelines.

From our production platform we are able to access two separate oil and natural gas markets thereby minimizing downtime risk and providing the ability to select the best sales price for our oil and natural gas production. Oil and natural gas production can flow through our 20” gas pipeline to third-party owned and operated onshore processing facilities near Patterson, Louisiana. Alternatively, natural gas can flow via our 8” pipeline to a third-party owned and operated onshore processing facility southwest of Abbeville, Louisiana, and oil can flow via a 6” oil pipeline to third-party owned and operated onshore processing facilities in St. Mary Parish, Louisiana. Production facilities include a turbine type compressor capable of servicing all Dutch and Mary Rose wells at the Eugene Island 11 platform. Condensate can also flow to onshore markets and multiple refineries.

Grand Isle Block 45/46 Area

In December 2019, we entered into a Joint Development Agreement with Juneau, that provides the Company the right to acquire an interest in up to six of Juneau's prospects located in the Gulf of Mexico. The first such prospect acquired by the Company is the Iron Flea prospect located in the Grand Isle Block 45 Area in the shallow waters off of the Louisiana coastline. Management considers this exploratory prospect to be an excellent complement to its PDP oriented acquisition strategy and believes it could provide a compelling economic value proposition, even in the current low oil price environment. See Note 4 – "Acquisitions and Dispositions" for more information. We anticipate spudding this prospect in the second quarter of 2020, and if successful, expect that the well could be producing in early 2021.

Vermilion 170 Field

For most of 2018, we owned and operated one well located in federal waters off of the Louisiana coast with a dedicated production facility at Vermilion 170. Effective December 1, 2018, this well was sold to a third-party independent oil and gas company in exchange for the buyer's assumption of the plugging and abandonment liability for the Vermilion 170 well, platform and associated pipeline, a retained ORRI in the Vermilion 170 well and an ORRI in any future wells drilled by the buyer on two nearby prospects that would produce through the Vermilion 170 platform if successful.

Central Oklahoma

During the three months ended December 31, 2019, we acquired producing properties in the Will Energy and White Star acquisitions that are located in the Central Oklahoma region and are primarily in the Woodford, Meramec, Mississippian, Chester, Oswego and Hunton formations. In December 2019, we completed and brought on production a Garfield County, Oklahoma well, which we acquired in connection with the White Star acquisition. As of December 31, 2019, the Central Oklahoma region included approximately 743,800 gross (286,700 net) acres, proved reserves of 133.5 Bcfe (58% oil/liquids) and 778 gross (449.6 net) producing wells.

Western Anadarko

During the three months ended December 31, 2019, we acquired producing properties in the Will Energy and White Star acquisitions that are located in the Western Anadarko region and are primarily in the Chester, Tonkawa, Morrow, Marmaton, Cottage Grove, Red Fork and Cleveland formations. As of December 31, 2019, the Western Anadarko region included approximately 303,200 gross (167,200 net) acres, proved reserves of 47.1 Bcfe (61% gas) and 592 gross (348.7 net) producing wells.

West Texas

Southern Delaware Basin

Since July 2016, we and our 50% working interest partner in the Southern Delaware Basin have increased our leasehold footprint from approximately 5,000 undeveloped acres, net to Contango, to approximately 8,000 acres, net to Contango. As of December 31, 2019, we estimate that we have proved reserves of 43.3 Bcfe (75% oil, 90% total liquids) in our West Texas region. We believe substantially all of the potential drilling locations on this acreage can accommodate 10,000 foot laterals.

During the three months ended December 31, 2019, we brought three wells online in the Southern Delaware Basin, the Iron Snake #1H, the Breakthrough State #1 H and the Old Ironside #1H, all of which are located in NE Bullseye. In January 2020, we brought one additional NE Bullseye well online, the State Spearhead #1H. NE Bullseye is expected to be a more productive and higher oil cut area that our Bullseye area and will be the focus of future capital spending in the area when we decide to become more aggressive in allocating capital to our drilling program.

As of December 31, 2019, we had twelve wells producing from the Wolfcamp A, five wells producing from the Wolfcamp B, and a sixth well drilled in the Wolfcamp A which was completed in January 2020. Our West Texas production during the three months ended December 31, 2019 was approximately 8.3 Mmcfe per day.

Other Onshore

Our Other Onshore region is comprised of various smaller non-core producing areas in Texas, Louisiana, Wyoming and Mississippi. Our estimated net proved reserves for the properties in this region are 58.0 Bcfe.

Texas

Our Southeast Texas area includes approximately 19,500 gross (11,700 net) acres in Madison and Grimes counties, with a multi-year inventory of potential drilling locations encompassing the Woodbine, Eagle Ford Shale and/or Georgetown/Buda formations. We had proved reserves of 42.7 Bcfe (87% oil/liquids) and 49 gross (29.2 net) producing wells in Southeast Texas as of December 31, 2019.

Our South Texas area includes properties in the Dimmitt and Zavala counties part of this area, which we believe approximately 16,100 gross (6,600 net) acres of to be prospective for the Buda, Georgetown and Eagle Ford Shale plays. Our South Texas area also includes approximately 17,500 gross (8,400 net) acres located in conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved reserves in this area were 5.9 Bcfe (54% gas) with 51 gross (23.2 net) producing wells, as of December 31, 2019.

Our East Texas area included approximately 5,900 gross (3,600 net) acres primarily in San Augustine County, with proved reserves of 0.9 Bcfe (84% gas) and 8 gross (4.7 net) producing wells. We believe that the further exploitation of our acreage in the Haynesville, Mid-Bossier and James Lime formations may provide long-term natural gas reserve and production growth potential in the future. There has been renewed interest in this area by offset operators as they experiment with new frac techniques and refracing of previously drilled wells.

No drilling capital has been allocated to these Texas areas since 2015 due to the low commodity price environment and our focus on our West Texas region properties, with the exception of four successful non-operated Georgetown wells in which we participated in drilling from 2017 through 2019.

In 2018, we commenced a program to rationalize our minor, non-core assets located in South and Southeast Texas. We sold Eagle Ford Shale assets in Karnes County, Texas for $21.0 million; Gulf Coast conventional assets in Southeast Texas for $6.0 million, and Gulf Coast conventional and unconventional assets in South Texas for $0.9 million. In 2019, we sold certain non-core operated assets located in Lavaca and Wharton counties, Texas and Frio and Zavala counties, Texas, respectively, in exchange for the buyers' assumption of the plugging and abandonment liabilities of the sold properties. In addition to the cash proceeds received for the divestitures noted, we also were successful in reducing our responsibility for asset retirement obligations by a total of $0.8 million and $8.6 million (undiscounted net) in 2019 and 2018, respectively.

Louisiana

As of December 31, 2019, the estimated proved reserves for our Louisiana properties were 6.7 Bcfe (40% oil) primarily related to the properties we acquired in the Will Energy acquisition.

Wyoming

In 2015, we drilled the first of three successful wells in this area targeting the Muddy Sandstone formation. As a result of drilling these wells, we have satisfied the right to earn 35,000 net acres, of which approximately 27,800 net acres we still control. However, approximately 70% of such acreage will expire within the next three years if no drilling activity is conducted. Based on prior drilling results, a sustained improvement in oil prices will be needed to justify allocation of drilling capital to this area at the expense of other areas in our portfolio that provide higher returns. As of December 31, 2019, the estimated proved reserves for this area were 1.7 Bcfe (100% oil).

Mississippi

As of December 31, 2019, we held approximately 1,300 gross (300 net) mostly undeveloped acres in Mississippi.

Impairment of Long-Lived Assets

We recognized $117.8 million in non-cash impairment charges of proved properties due to reserve revisions during the year ended December 31, 2019. Included in that impairment charge was $34.5 million related to our proved offshore Gulf of Mexico properties, primarily a result of a reassessment of future operating costs and a revision to the reservoir decline model for the expected decline in recoverable condensate volumes. In addition, we recognized onshore proved property impairment expense of $83.3 million, including $73.7 million in the Bullseye area in our West Texas region and $9.6 million in our Other Onshore region. The onshore impairment was primarily due to performance revisions and changes in realizable prices on the producing properties, which impacted the expected economics for proved undeveloped locations in these areas, which then resulted in the elimination of certain proved undeveloped locations due to the SEC's five year development rule for such locations.

Under US GAAP, an impairment charge is required when the unamortized capital cost of a field within the Company's proved property base exceeds the risked estimated future net cash flows from the proved, probable and possible reserves for that field. In 2019, we recognized non-cash unproved impairment expense of approximately $9.2 million related primarily to lease expirations, and near-term expirations, in the Bullseye area of our West Texas region.

If oil or natural gas prices continue to decline further from those prices in effect at December 31, 2019, we may be required to record additional non-cash impairment in the future, thereby impacting our financial results for that period.

Onshore Investments

Jonah Field – Sublette County, Wyoming

Our wholly-owned subsidiary, Contaro Company ("Contaro"), owns a 37% ownership interest in Exaro. As of December 31, 2019, we had invested approximately $46.9 million in Exaro, with no requirement to make any additional equity contributions, as our commitment to invest additional capital in Exaro expired on March 31, 2017. We account for Contaro's ownership in Exaro using the equity method of accounting, and therefore, do not include its share of individual operating results, reserves or production in those reported in our consolidated results.

As of December 31, 2019, Exaro had 648 wells on production over its 5,760 gross acres (1,040 net acres), with a working interest between 14.6% and 32.5%. These wells were producing at a rate of approximately 18 Mmcfe/d, net to Contango. For the year ended December 31, 2019, the Company recognized a net investment gain of approximately $1.0 million, net of zero tax expense, as a result of its equity investment in Exaro. As of December 31, 2019, reserves attributable to our investment in Exaro were 23.0 Bcfe. See Note 11 - "Investment in Exaro Energy III LLC" for additional details related to this equity investment.

Title to Properties

From time to time, we are involved in legal proceedings relating to claims associated with ownership interests in our properties. We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, and liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed independent third party attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our natural gas and oil properties to secure our Credit Agreement. These mortgages and the related Credit Agreement contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 13 to our Financial Statements - "Long-Term Debt" for further information.

Marketing and Pricing

We derive our revenue principally from the sale of natural gas and oil. As a result, our revenues are determined, to a large degree, by prevailing natural gas and oil prices. We sell a portion of our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to three years and oil and condensate production to purchasers under sales agreements with primary terms of up to one year. The sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments, while the sale prices for oil are tied to industry standard posted prices, subject to negotiated price adjustments.

We typically utilize commodity price hedge instruments to minimize exposure to declining prices on our oil, natural gas and natural gas liquids production, by using a series of swaps and/or costless collars. Unrealized gains or losses associated with hedges vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities being hedged.

We currently have hedges in place for 70% and 67% of currently forecasted PDP oil production for 2020 and 2021, respectively, at average floor prices of $55.13 and $51.71 per barrel, respectively. For natural gas, we have 68% and 57% of currently forecasted PDP production for 2020 and 2021, respectively, hedged at average floor prices of $2.57 and $2.49 per mmbtu, and 76% of forecasted PDP production for the first quarter of 2022 hedged with swaps at $2.54 per mmbtu. Approximately 98% of our hedges are swaps, and we have no three way collars or short puts.

As of December 31, 2019, we had the following derivative contracts in place:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Natural Gas	Jan 2020 - March 2020	Swap	425,000 Mmbtus	$ 2.841 (1)
Natural Gas	Jan 2020 - March 2020	Collar	225,000 Mmbtus	$ 2.45 - $ 3.40 (1)
Natural Gas	April 2020 - July 2020	Swap	400,000 Mmbtus	$ 2.532 (1)
Natural Gas	Aug 2020 - Oct 2020	Swap	40,000 Mmbtus	$ 2.532 (1)
Natural Gas	Nov 2020 - Dec 2020	Swap	375,000 Mmbtus	$ 2.696 (1)
Natural Gas	Jan 2020 - March 2020	Swap	300,000 Mmbtus	$ 2.53 (1)
Natural Gas	April 2020 - July 2020	Swap	400,000 Mmbtus	$ 2.53 (1)
Natural Gas	Aug 2020 - Dec 2020	Swap	350,000 Mmbtus	$ 2.53 (1)
Natural Gas	Jan 2020 - March 2020	Swap	300,000 Mmbtus	$ 2.532 (1)
Natural Gas	April 2020 - July 2020	Swap	400,000 Mmbtus	$ 2.532 (1)
Natural Gas	Aug 2020 - Dec 2020	Swap	350,000 Mmbtus	$ 2.532 (1)
Oil	Jan 2020 - June 2020	Swap	22,000 Bbls	$ 57.74 (2)
Oil	July 2020 - Dec 2020	Swap	15,000 Bbls	$ 57.74 (2)
Oil	Jan 2020 - March 2020	Swap	2,700 Bbls	$ 54.33 (2)
Oil	April 2020 - June 2020	Swap	2,500 Bbls	$ 54.33 (2)
Oil	July 2020	Swap	5,500 Bbls	$ 54.33 (2)
Oil	Aug 2020 - Oct 2020	Swap	2,500 Bbls	$ 54.33 (2)
Oil	Nov 2020 - Dec 2020	Swap	3,500 Bbls	$ 54.33 (2)
Oil	Jan 2020 - Feb 2020	Swap	42,500 Bbls	$ 54.70 (2)
Oil	March 2020 - July 2020	Swap	37,500 Bbls	$ 54.70 (2)
Oil	Aug 2020 - Dec 2020	Swap	35,000 Bbls	$ 54.70 (2)
Oil	Jan 2020 - Feb 2020	Swap	42,500 Bbls	$ 54.58 (2)
Oil	March 2020 - July 2020	Swap	37,500 Bbls	$ 54.58 (2)
Oil	Aug 2020 - Dec 2020	Swap	35,000 Bbls	$ 54.58 (2)

Oil	Jan 2020 - Oct 2020	Collar	3,442 Bbls	$ 52.00 - $ 65.70	(2)
Natural Gas	Jan 2021 - March 2021	Swap	185,000 Mmbtus	$ 2.505	(1)
Natural Gas	April 2021 - July 2021	Swap	120,000 Mmbtus	$ 2.505	(1)
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000 Mmbtus	$ 2.505	(1)
Natural Gas	Jan 2021 - March 2021	Swap	185,000 Mmbtus	$ 2.508	(1)
Natural Gas	April 2021 - July 2021	Swap	120,000 Mmbtus	$ 2.508	(1)
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000 Mmbtus	$ 2.508	(1)
Natural Gas	Jan 2021 - March 2021	Swap	650,000 Mmbtus	$ 2.508	(1)
Natural Gas	April 2021 - Oct 2021	Swap	400,000 Mmbtus	$ 2.508	(1)
Natural Gas	Nov 2021 - Dec 2021	Swap	580,000 Mmbtus	$ 2.508	(1)
Oil	Jan 2021 - March 2021	Swap	19,000 Bbls	$ 50.00	(2)
Oil	April 2021 - July 2021	Swap	12,000 Bbls	$ 50.00	(2)
Oil	Aug 2021 - Sept 2021	Swap	10,000 Bbls	$ 50.00	(2)
Oil	Jan 2021 - July 2021	Swap	62,000 Bbls	$ 52.00	(2)
Oil	Aug 2021 - Sept 2021	Swap	55,000 Bbls	$ 52.00	(2)
Oil	Oct 2021 - Dec 2021	Swap	64,000 Bbls	$ 52.00	(2)

(1) Based on Henry Hub NYMEX natural gas prices.

(2) Based on West Texas Intermediate oil prices.

In addition to the above financial derivative instruments, we also had a costless swap agreement with a Midland WTI – Cushing oil differential swap price of $0.05 per barrel of oil. The agreement fixes the Company's exposure to that differential on 12,000 barrels of oil per month for January 2020 through June 2020 and 10,000 barrels per month for July 2020 through December 2020.

In March 2020, the Company entered into the following additional derivative contracts:

Commodity	Period	Derivative	Volume/Month	Price/Unit	
Natural Gas	April 2021 - Nov 2021	Swap	70,000 Mmbtus	$ 2.36	(1)
Natural Gas	Dec 2021	Swap	350,000 Mmbtus	$ 2.36	(1)
Natural Gas	Jan 2022 - March 2022	Swap	780,000 Mmbtus	$ 2.54	(1)

(1) Based on Henry Hub NYMEX natural gas prices.

Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. The largest purchaser of our production for the year ended December 31, 2019, calculated on an equivalent basis, was ConocoPhillips Company (36.4%). As a result of our acquisition of White Star, additional purchasers that will acquire a meaningful percentage of our production in the future are Enlink Midstream Operating, LP (11.6% of combined December 2019 production), Mustang Gas Products, LLC and Valero Marketing and Supply Company. This concentration may increase our overall exposure to credit risk, and our purchasers will likely be similarly affected by changes in economic and industry conditions. Our financial condition and results of operations could be materially adversely affected if one or more of our significant purchasers fails to pay us or ceases to acquire our production on terms that are favorable to us. However, we believe our current purchasers could be replaced by other purchasers under contracts with similar terms and conditions.

Competition

The oil and gas industry is highly competitive, and we compete with numerous other companies. Our competitors in the exploration, development, acquisition and production business include major integrated oil and gas companies as well as numerous independent companies, including many that have significantly greater financial resources.

The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties and obtaining purchasers and transporters for the natural gas and oil we produce. There is also competition between producers of natural gas and oil and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state and local governments; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing natural gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Governmental Regulations and Industry Matters

Industry Regulations

The availability of a ready market for oil, natural gas and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of oil, natural gas and natural gas liquids production, federal, state and local regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of oil, natural gas and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities, and the marketing of competitive fuels. For example, a productive natural gas well may be “shut-in” because of an oversupply of natural gas or lack of an available natural gas pipeline in the area in which the well is located. State and federal regulations generally are intended to prevent waste of oil, natural gas and natural gas liquids, protect rights to produce oil, natural gas and natural gas liquids between owners in a common reservoir, control the amount of oil, natural gas and natural gas liquids produced by assigning allowable rates of production, and protect the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted.

The following discussion summarizes the regulation of the U.S. oil and gas industry. Such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Oil, Natural Gas and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. 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 and the density of wells that may be drilled in and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws, which establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil, natural gas and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act of 1938 (the “NGA”), the Federal Energy Regulatory Commission (the “FERC”) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the “Decontrol Act”) deregulated natural gas prices for all “first sales” of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC’s jurisdiction over natural gas transportation.

Section 1(b) of the NGA exempts gas gathering facilities from the FERC's jurisdiction. We believe that the gas gathering facilities we own meet the traditional tests the FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. While we own some gas gathering facilities, we also depend on gathering facilities owned and operated by third parties to gather production from our properties, and therefore, we are affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulation affect the rates charged for gathering services, we also may be affected by these changes. Accordingly, we do not anticipate that we would be affected any differently than similarly situated gas producers.

Under the provisions of the Energy Policy Act of 2005 (the “2005 Act”), the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission (the “CFTC”) also holds authority to monitor certain segments of the physical and derivative futures commodity markets including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. FERC holds substantial enforcement authority, including the ability to potentially assess maximum civil penalties of approximately $1.24 million per day per violation, subject to annual adjustment for inflation. CFTC also holds substantial enforcement authority, including the ability to potentially assess maximum civil penalties of up to approximately $1.21 million per violation or triple the monetary gain.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. For example, on December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their 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. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC’s policy statement on price reporting. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704 as clarified in orders on clarification and rehearing. In addition, to the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC’s regulations could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978 (the “NGPA”), the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required interstate pipelines, among other things, to perform “open access” transportation of gas for others, “unbundle” their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular interstate pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC's other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the natural gas industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. We do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the "FTC") prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to potentially assess maximum civil penalties of approximately $1.18 million per day per violation, subject to annual adjustment for inflation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of oil and natural gas liquids transportation rates may tend to increase the cost of transporting oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with oil production from our oil producing operations.

There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. We do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of petroleum with which we compete.

Environmental and Occupational Health and Safety Matters

Our oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment, or otherwise relating to environmental protection. Numerous governmental authorities, including the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause us to incur significant capital expenditures or costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays, cancellations or restrictions in permitting or performance of projects and the issuance of orders enjoining some or all of our operations in affected areas. The public continues to have a significant interest in the protection of the environment. The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment, and thus any new laws and regulations, amendment of existing laws and regulations, reinterpretation of legal requirements or increased governmental enforcement that result in more stringent and costly exploration, production and development activities, or waste handling, storage transport, disposal or remediation requirements could result in increased costs of our doing business and consequently affect our profitability. 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.

The federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund Law", and similar state laws, impose strict joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These potentially responsible persons include the current or past owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property or natural resource 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 also generate wastes that are subject to the federal Resource Conservation and Recovery Act, as amended (the "RCRA"), and comparable state statutes. The RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of nonhazardous and hazardous wastes, and the EPA and analogous state agencies stringently enforce the approved methods of management and disposal of these wastes. While the RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements, we can provide no assurance that this exemption will be preserved in the future. Any removal of this exclusion could increase the amount of waste we are required to manage and dispose of as hazardous waste rather than non-hazardous waste, and could cause us to incur increased operating costs, which could have a significant impact on us as well as the natural gas and oil industry in general.

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

There remains continued public, governmental and scientific attention regarding climate change, with the EPA having determined that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment. As a result, the EPA has adopted regulations under existing provisions of the CAA that, among other things, impose permit reviews and restrict emissions of GHGs from certain large stationary sources. These EPA regulations could adversely affect our operations and restrict, delay or halt our ability to obtain air permits for new or modified sources. Additionally, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including certain onshore and offshore production facilities, which include the majority of our operations. We are monitoring and annually reporting on GHG emissions from certain of our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that include consideration of cap-and-trade programs whereby major sources of GHG emissions are required to acquire and surrender emission allowances in return for emitting those GHGs, as well as carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Internationally, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement, which was signed by the United States in April 2016, requires countries to review and "represent a progression" in their intended nationally determined contributions, which set greenhouse gas emission reduction goals, every five years beginning in 2020. In November 2019, the United States began the process to withdraw from the Paris Agreement by submitting formal notifications to the United Nations, but the withdrawal will not take effect until one year from delivery of the notification, which would result in an effective exit date of November 2020. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future international, federal or state laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

The Federal Water Pollution Control Act, as amended (the "Clean Water Act") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. Any such discharge of pollutants into regulated waters is prohibited except in accordance with the terms of an issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. The EPA and the U.S. Army Corps of Engineers released a rule to revise the definition of "waters of the United States," or WOTUS, for all Clean Water Act programs, which went into effect in August 2015. However, in September 2019, the EPA repealed the 2015 rule, and in January 2020 finalized a new rule narrowing the scope of the WOTUS definition. The repeal of the 2015 is currently subject to legal challenge, and the revised WOTUS definition of 2020 is expected to be subject to legal challenge once it legally takes effect on March 23, 2020.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended (the "SDWA"), and analogous state laws. Our oil and natural gas exploration and production operations generate produced water, drilling muds and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations, and thus, those activities are subject to the SWDA. The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities that may be injected, and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for alternative water supplies, property and natural resource damages and personal injuries. Furthermore, in response to a growing concern that the injection of produced water and other fluids into belowground disposal wells triggers seismic activity in certain areas, some states, including Texas and Oklahoma, where we operate, have imposed, and other states are considering imposing, additional requirements in the permitting or operation of produced water injection wells. In Texas, the Texas Railroad Commission ("TRC") has adopted a final rule governing the permitting or re-permitting of disposal wells that requires, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. In Oklahoma, the Oklahoma Corporation Commission issued various orders and regulations applicable to disposal operations in specific counties in Oklahoma in 2016. These rules require that disposal well operators, among other things, conduct additional mechanical integrity testing, make sure that their wells are not injecting wastes into targeted formations, and/or reduce the volumes of wastes disposed in such wells. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and natural gas activities utilizing injection wells for produced water disposal. These existing and any new seismic requirements applicable to disposal wells that impose more stringent permitting or operational requirements could result in added costs to comply or, perhaps, may require alternative methods of disposing of produced water and other fluids, which could delay production schedules and also result in increased costs.

The federal Oil Pollution Act of 1990, as amended (the "OPA"), and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. The OPA applies to vessels, onshore facilities and offshore 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 and lessees and permittees of offshore leases 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. In January 2018, the federal Bureau of Ocean Energy Management ("BOEM") raised the OPA's damages liability cap to $137.7 million; however, while liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. The OPA requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill, and to prepare and submit for approval oil spill response plans. These oil spill response plans must detail the action to be taken in the event of a spill; identify contracted spill response equipment, materials, and trained personnel; and identify the time necessary to deploy these resources in the event of a spill. The OPA currently requires a minimum financial responsibility demonstration of between $35 million and $150 million for companies operating on the federal Outer Continental Shelf (“OCS”) waters, including the Gulf of Mexico. We are currently required to demonstrate, on an annual basis, that we have ready access to $35 million that can be used to respond to an oil spill from our facilities on the OCS. In addition, to the extent our offshore lease operations affect state waters, we may be subject to additional state and local clean-up requirements or incur liability under state and local laws.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely use hydraulic fracturing techniques in many of our completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or other similar state agencies, but several federal agencies have also asserted regulatory authority over, or conducted investigations that focus upon, certain aspects of the process, including a suite of proposed rulemakings and final rules issued by the EPA and the federal Bureau of Land Management (the “BLM”), which legal requirements, to the extent finalized and implemented by the agencies, may impose more stringent requirements relating to the composition of fracturing fluids, emissions and discharges from hydraulic fracturing, chemical disclosures, and performances of fracturing activities on federal and Indian lands. Congress has from time to time considered, but not enacted, legislation to provide for federal regulation or the banning of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process while, at the state level, several states, including Texas and Wyoming, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells.

The National Environmental Policy Act, as amended (“NEPA”) is applicable to oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM. 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. Governmental permits or authorizations that are subject to the requirements of NEPA are required for exploration and development projects on federal and Indian lands. This process has the potential to delay, limit or increase the cost of developing 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.

The federal Endangered Species Act, as amended (“ESA”), provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States and prohibits taking of endangered species. The ESA may impact exploration, development and production activities on public or private lands. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act, as amended. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of one or more settlements entered into by the U.S. Fish and Wildlife Service (the “FWS”), the agency is required to make a determination on listing of numerous species as endangered or threatened under the ESA by specified timelines. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures as well as time delays or limitations on or cancellations of our drilling program activities, which costs, delays, limitations or cancellations could have an adverse impact on our ability to develop and produce reserves.

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the U.S. Occupational Safety and Health Administration hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

The BOEM and the BSEE, each agencies of the U.S. Department of the Interior, have, over time, imposed more stringent permitting procedures and regulatory safety and performance requirements for wells in federal waters. For example, in 2016, the BOEM issued a Notice to Lessees and Operators (the “NTL #2016-N01”) that became effective in September 2016 and bolsters supplemental financial assurance requirements for the decommissioning of offshore wells, platforms, pipelines and other facilities whereas the BSEE has issued various regulations relating to the safe and environmentally responsible development of energy and mineral resources on the OCS that have resulted in more stringent requirements including, for example, well and blowout preventer design, workplace safety and corporate accountability. Additionally, states may adopt and implement similar or more stringent legal requirements applicable to exploration and production activities in state waters. Compliance with these more stringent regulatory restrictions, together with any uncertainties or inconsistencies in current decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect, delay or cancel new drilling and ongoing development efforts. If the BOEM determines that increased financial assurance is required in connection with our offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled. Also, if material spill incidents were to occur, the United States could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which developments could have a material adverse effect on our business. Any of the offshore-related matters described above could have a material adverse effect on our business, financial condition and results of operations.

These regulatory actions, or any new rules, regulations or legal initiatives that may be adopted or enforced by the BOEM or the BSEE in the future could delay or disrupt our oil and natural gas exploration and production operations conducted offshore, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit or cancel activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases.

Moreover, under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee, or any subsequent assignee, is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BOEM to decommission OCS facilities that one of our assignees, or any subsequent assignee, of offshore facilities is unwilling or unable to perform, we could incur costs to perform decommissioning, which costs could be material. If the BOEM determines that increased financial assurance is required in connection with our or any previously assigned offshore facilities but we are unable to provide the necessary supplemental bonds or other forms of financial assurance, the BOEM could impose monetary penalties or require our operations on federal leases to be suspended or cancelled.

See “Item 1A. Risk Factors” for further discussion on hydraulic fracturing; ozone standards; climate change, including methane or other GHG emissions; releases of regulated substances; offshore regulatory safety and environmental development requirements, and other aspects of compliance with legal or financial assurance requirements or relating to environmental protection, including with respect to offshore leases. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards or more stringent enforcement programs continue to evolve.

Other Laws and Regulations

Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of natural gas and oil including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit the number of wells that could be drilled on the

Company’s properties and to limit the allowable production from the successful wells completed on the Company’s properties, thereby limiting the Company’s revenues.

Whereas the BLM administers oil and natural gas leases held by the Company on federal onshore lands, the BOEM administers the natural gas and oil leases held by the Company on federal offshore tracts on the OCS. The Office of Natural Resources Revenue (the “ONRR”) collects a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the ONRR changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the regulations generally do not impact the Company to any greater extent than other similarly situated producers.

To cover the various obligations of lessees on the OCS, such as the cost to plug and abandon wells, decommission or remove platforms and pipelines, and clear the seafloor of obstructions at the end of production (collectively, “decommissioning obligations”), the BOEM generally requires that lessees post supplemental bonds or other acceptable financial assurances that such obligations will be met. Historically, our financial assurance costs to satisfy decommissioning obligations have not had a material adverse effect on our results of operations; however, the BOEM continues to consider imposing more stringent financial assurance requirements on offshore operators on the OCS. For example, the BOEM issued NTL #2016-N01 that went into effect in September 2016 and augments requirements for the posting of additional financial assurance by offshore lessees, among others, to assure that sufficient funds are available to satisfy decommissioning obligations on the OCS. If the BOEM determines under this new NTL that a company does not satisfy the minimum requirements to qualify for providing self-insurance to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. In June 2017, the BOEM extended indefinitely the start date for implementation of NTL #2016-N01. This extension currently remains in effect; however, the BOEM reserved the right to re-issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder’s decommissioning obligations.

The BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the BOEM determines whether and to what extent any additional financial assurance may be required by us with respect to our offshore operations, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could in the future make other demands for additional financial assurances covering our obligations under sole liability properties and/or non-sole liability properties. In the event that we are unable to obtain the additional required bonds or assurances as requested, the BOEM may require certain of our operations on federal leases to be suspended or cancelled or otherwise impose monetary penalties. See “Item 1A. Risk Factors” for a further discussion on BOEM and its implementation of NTL #2016-N01.

Risk and Insurance Program

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties, including such occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice, and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We continuously monitor regulatory changes and regulatory responses and their impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection at a level that we can afford considering the cost of insurance, against the potential and magnitude of disruption to our operations and cash flows. Changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico could lead to tighter underwriting standards, limitations on scope and amount of coverage and higher premiums, including possible increases in liability caps for claims of damages from oil spills.

Health, Safety and Environmental Program

Our Health, Safety and Environmental (“HS&E”) Program is supervised by senior management to ensure compliance with all state and federal regulations. In support of the operating committee, we have contracted with J. Connor Consulting (“JCC”) to coordinate the regulatory process relative to our offshore assets. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico. They provide preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills on behalf of oil and gas companies and pipeline operators.

Additionally, in support of our Gulf of Mexico operations, we have established a Regional Oil Spill Response Plan which has been approved by the BSEE. Our response team is trained annually and is tested through in-house spill drills. We have also contracted with O'Brien's Response Management ("O'Brien's"), who maintains an incident command center on 24 hour alert in Houston, TX. In the event of an oil spill, the Company's response program is initiated by notifying O'Brien's of any reportable incident. While the Company response team is mobilized to focus on source control and containment of the spill, O'Brien's coordinates communications with state and federal agencies and provides subject matter expertise in support of the response team.

We also have contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs in the event of a spill. CGA specializes in onsite control and cleanup and is on 24-hour alert with equipment currently stored at eight bases along the gulf coast, from South Texas to East Louisiana. The CGA equipment stockpile is available to serve member oil spill response needs and includes open seas skimmers, shoreline protection boom, communications equipment, dispersants with application systems, wildlife rehabilitation and a forward command center. CGA has retainers with aerial dispersant and mechanical recovery equipment contractors for spill response.

In addition to our membership in CGA, the Company has contracted with Wild Well Control for source control at the wellhead, if required. Wild Well Control is one of the world's leading providers of firefighting and well control services.

We also have a full time health, safety and environmental professional who supports our operations and oversees the implementation of our onshore HS&E policies.

Safety and Environmental Management System

We have developed and implemented a Safety and Environmental Management System ("SEMS") to address oil and gas operations in the OCS, as required by the BSEE. Our SEMS identifies and mitigates safety and environmental hazards and the impacts of these hazards on design, construction, start-up, operation, inspection and maintenance of all new and existing facilities. The Company has established goals, performance measures, training and accountability for SEMS implementation. We also provide the necessary resources to maintain an effective SEMS, and we review the adequacy and effectiveness of the SEMS program annually. Company facilities are designed, constructed, maintained, monitored and operated in a manner compatible with industry codes, consensus standards and all applicable governmental regulations. We have contracted with Island Technologies Inc. to coordinate our SEMS program and to track compliance for production operations.

The BSEE enforces the SEMS requirements through regular audits. Failure of an audit may result in an Incident of Non-Compliance and could ultimately result in the assessment of civil penalties and/or require a shut-in of our Gulf of Mexico operations if not resolved within the required time.

Employees

On December 31, 2019, we had 124 full time employees, of which 62 were field personnel. Half of our employees were previous White Star employees at the time of the acquisition. We have been able to attract and retain a talented team of industry professionals that have been successful in achieving significant growth and success in the past. As such, we are well-positioned to adequately manage and develop our existing assets and also to increase our proved reserves and production through exploitation of our existing asset base, as well as the continuing identification, acquisition and development of new growth opportunities. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

In addition to our employees, we use the services of independent consultants and contractors to perform various professional services. As a working interest owner, we rely on certain outside operators to drill, produce and market our natural gas and oil where we are a non-operator. In prospects where we are the operator, we rely on drilling contractors to drill and sometimes rely on independent contractors to produce and market our natural gas and oil. In addition, we frequently utilize the services of independent contractors to perform field and on-site drilling and production operation services and independent third party engineering firms to evaluate our reserves.

Corporate Offices

Our principle corporate office is located at 717 Texas Avenue in downtown Houston, Texas, under a lease that expires March 31, 2021. Rent, including parking, related to this office space for the year ended December 31, 2019 was approximately $0.6 million. We also have a corporate office located at 301 NW 63rd Street, Oklahoma City, Oklahoma, which we acquired through the White Star Acquisition. See Note 4 – "Acquisitions and Dispositions" for more information. The lease for this office was amended effective December 1, 2019, upon the closing of the White Star acquisition, and expires January 31, 2022. Rent, including parking, related to this office space is expected to be approximately $20,000 per month through the expiration.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us. Filings made with the SEC electronically are publicly available through the SEC's website at http://www.sec.gov, and we make these documents available free of charge at our website at http://www.contango.com as soon as reasonably practicable after they are filed or furnished with the SEC. This report on Form 10-K, including all exhibits and amendments, has been filed electronically with the SEC. We intend to use our website as a Regulation FD compliant means of making public disclosures. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this report.

Seasonal Nature of Business

The demand for oil and natural gas fluctuates depending on the time of year. Seasonal anomalies such as mild winters or cooler summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand.

Item 1A. *Risk Factors*

In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following factors when evaluating the Company, as well as all other information presented in this Form 10-K. An investment in the Company is subject to risks inherent in our business, and the risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we may currently deem immaterial, may become important factors that harm our business, results of operations and financial condition in the future. The trading price of the shares of the Company is affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in the Company may decrease, resulting in a loss.

We have no ability to control the market price for natural gas, NGLs and oil. Natural gas, NGL and oil prices fluctuate widely, and a continued substantial or extended decline in natural gas and oil prices would adversely affect our revenues, profitability and growth and could have a material adverse effect on our business, results of operations and financial condition.

Our revenues, profitability and future growth depend significantly on natural gas, NGL and oil prices. Natural gas prices, NGL prices and oil prices remained low during the past several years relative to the high prices in 2014 and have declined quickly and substantially in February and March 2020. The markets for these commodities are volatile and prices received affect the amount of future cash flow available for capital expenditures, repayment of indebtedness and our ability to raise additional capital. Lower prices also affect the amount of natural gas, NGLs and oil that we can economically produce. Prices fluctuate and decline based on factors beyond our control. Factors that can cause price fluctuations and declines include:

- Overall economic and market conditions, domestic and global.
- The domestic and foreign supply of natural gas and oil.
- The level of consumer product demand.

- The cost of exploring for, developing, producing, refining and marketing natural gas, NGLs and oil.
- Adverse weather conditions, natural disasters, climate change and health emergencies and pandemics, such as the recent novel coronavirus (COVID-19) outbreak.
- The price and availability of competitive fuels such as LNG, heating oil and coal, and alternative fuels.
- The level of LNG imports and exports and natural gas exports.
- Political and economic conditions in the Middle East and other natural gas and oil producing regions.
- The ability of the members of OPEC and other oil exporting nations to agree to and maintain oil price and production controls.
- Domestic and foreign governmental regulations, including temporary orders limiting economic activity.
- Special taxes on production or the loss of tax credits and deductions.
- Technological advances affecting energy consumption and sources of energy supply.
- Access to pipelines and gas processing plants and other capacity constraints or production disruptions.
- The effects of energy conservation efforts, including by virtue of shareholder activism or activities of non-governmental organizations.

A substantial or extended decline in natural gas, NGL and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas, NGLs and oil that may be economically produced by us. The Company may utilize financial derivative contracts, such as swaps, costless collars and puts on commodity prices, to reduce some of the exposure to potential declines in commodity prices. However, these derivative contracts may not be sufficient to mitigate the effect of lower commodity prices.

The widespread outbreak of an illness, pandemic or any other public health crisis may have material adverse effects on our business, financial position, results of operations and/or cash flows.

In December 2019, a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19, was reported to have surfaced in China. The spread of this virus has caused business disruption beginning in January 2020, including disruption to the oil and natural gas industry. In March 2020, the World Health Organization declared the outbreak of COVID-19 to be a pandemic, and the U.S. economy began to experience pronounced effects. The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains, reduced global demand for oil and gas, and created significant volatility and disruption of financial and commodity markets. The extent of the impact of the COVID-19 pandemic on our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including the demand for oil and natural gas, the availability of personnel, equipment and services critical to our ability to operate our properties and the impact of potential governmental restrictions on travel, transports and operations. There is uncertainty around the extent and duration of the disruption. The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our results will depend on future developments, which are highly uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus or treat its impact, its impact on the economy and market conditions, and how quickly and to what extent normal economic and operating conditions can resume. Therefore, while the Company expects this matter will likely disrupt our operations in some way, the degree of the adverse financial impact cannot be reasonably estimated at this time.

Part of our strategy involves drilling in new or emerging plays, and a reduction in our drilling program may affect our revenues and access to capital.

The results of our drilling in new or emerging plays are more uncertain than drilling results in areas that are more developed and with longer production history. Since new or emerging plays and new formations have limited production history, we are less able to use past drilling results in those areas to help predict our future drilling results. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. We may be unable to execute our expected drilling program in these areas because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services or otherwise, and/or oil, natural gas and NGL price declines. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

As a result of the continuing turmoil in the energy commodity price markets, we do not currently plan to commit any additional near-term drilling capital to West Texas, or other areas within our portfolio, except to fulfill leasehold commitments, preserve core acreage and, where determined appropriate to do so, expand our presence in those existing areas, or to add production and cash flow through new individual drilling projects at attractive rates of return. Without any incremental production resulting from our acquisition efforts, any further reduction in our drilling program will adversely affect our future production levels and future cash flow generated from operations. Furthermore, to the extent we are unable to execute our expected drilling program, our return on investment may not be as attractive as we anticipate, and our common stock price may decrease.

If we are unable to comply with restrictions and covenants in our Credit Agreement, there could be a default under the terms of the agreement, which could result in an acceleration of payments of funds that we have borrowed.

On September 17, 2019, we entered into a new revolving credit agreement with JPMorgan Chase Bank, N.A. and other lenders (the “Credit Agreement”), which established an initial borrowing base of $65 million. The Credit Agreement was amended on November 1, 2019, in conjunction with the closing of the Will Energy and White Star acquisitions, to add two additional lenders and increase the borrowing base thereunder to $145 million. See Note 4 – “Acquisitions and Dispositions” for more information.

The Credit Agreement contains various affirmative and negative covenants. These negative covenants may limit the Company’s ability to, among other things: incur additional indebtedness; make loans to others; make investments; enter into mergers; make or declare dividends or distributions; enter into commodity hedges exceeding a specified percentage of the Company’s expected production; enter into interest rate hedges exceeding a specified percentage of the Company’s outstanding indebtedness; incur liens; sell assets, including any of the Company’s oil and gas properties, unless the Company complies with certain conditions; and engage in certain other transactions without the prior consent of the lenders. Our ability to comply with the financial and other restrictive covenants in our indebtedness is uncertain and will be affected by our future performance and events or circumstances beyond our control. We may be required to seek waivers under the Credit Agreement and modifications of covenants, or to reduce our debt by, among other things, reducing our bank borrowing base, issuing equity or completing asset sales and other liquidity-enhancing activities, and these efforts may not be successful. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the Credit Agreement or other agreements governing our indebtedness, an event of default could result, which could permit acceleration of such debt and acceleration of our other debt. Any accelerated debt would become immediately due and payable.

Beginning in 2020, the semi-annual redeterminations of our bank borrowing base will occur on May 1st and November 1st of each year. The borrowing base may also be adjusted by certain events, including the incurrence of any senior unsecured debt, material asset dispositions or liquidation of hedges in excess of certain thresholds. The lowering of our borrowing base would limit availability under our Credit Agreement and could require us to seek different forms of financing arrangements, and we may not be able to access other external financial resources sufficient to enable us to repay our debts. If the outstanding debt under our Credit Agreement were to ever exceed the borrowing base, we would be required to repay the excess amount within a short period. Such acceleration of indebtedness could require us to pursue strategic restructuring options, which would have a material adverse effect on the trading price of our common stock. Given the recent decline in market conditions and commodity prices, we can provide no assurance that our borrowing base will not be reduced at the redeterminations in May or November 2020.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of undeveloped acreage and/or a decline in our oil, natural gas and NGL reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil, natural gas and NGL reserves. We intend to finance our future capital expenditures primarily with cash flow from operations, borrowings under our Credit Agreement and/or proceeds from non-core asset sales, issuances of preferred and common stock (subject to market conditions). Our cash flow from operations and access to capital is subject to a number of variables, including:

- Our proved reserves.
- The level of oil, natural gas and natural gas liquids we are able to produce from existing wells.
- The prices at which oil, natural gas and natural gas liquids are sold.
- Our ability to acquire, locate and produce new reserves.

If our revenues decrease 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 at current levels, to further develop and exploit our current properties, or to conduct exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our Credit Agreement contains covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base redetermination results in a lower borrowing base under our Credit Agreement, we may be unable to obtain financing otherwise currently available under our Credit Agreement. Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil, natural gas and natural gas liquids reserves.

We rely on third-party contract operators to drill, complete and manage some of our wells, production platforms, pipelines and processing facilities and, as a result, we have limited control over the daily operations of such equipment and facilities.

We depend upon the services of third-party operators to operate drilling rigs, completion operations, offshore production platforms, pipelines, gas processing facilities and the infrastructure required to produce and market our natural gas, condensate and oil. We have limited influence over the conduct of operations by third-party operators. As a result, we have little control over how frequently and how long our operations are down or our production is shut-in when problems, weather and other production shut-ins occur. Poor performance on the part of, or errors or accidents attributable to, the operator of a project in which we participate may have an adverse effect on our results of operations and financial condition.

Failure of our working interest partners to fund their share of development costs could result in the delay or cancellation of future projects, which could have a materially adverse effect on our financial condition and results of operations.

Our working interest partners must be able to fund their share of investment costs through cash flow from operations, external credit facilities, or other sources. If our partners are not able to fund their share of costs, it could result in the delay or cancellation of future projects, resulting in a reduction of our reserves and production, which could have a materially adverse effect on our financial condition and results of operations.

We are exposed to the credit risks of our customers, contractual counterparties and derivative counterparties, and any material nonpayment or nonperformance by our customers, contractual counterparties or derivative counterparties could have a materially adverse effect on our financial condition and results of operations.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and contractual counterparties, which risks may increase during periods of economic uncertainty. Furthermore, some of our customers and contractual counterparties may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. To the extent one or more of our significant customers or counterparties is in financial distress or commences bankruptcy proceedings, contracts with these customers or counterparties may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. The inability of our customers and other contractual counterparties to pay amounts owed to us and to otherwise satisfy their contractual obligations to us, including pursuant to our current and future joint development agreements, may materially and adversely affect our business, financial condition, results of operations and cash flows.

In addition, our risk management activities are subject to the risks that a counterparty may not perform its obligation under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our risk management policies and procedures are not properly followed. Any material nonpayment or nonperformance by our customers or our derivative counterparties could have a materially adverse effect on our financial condition and results of operations.

Repeated offshore production shut-ins can possibly damage our well bores.

Our offshore well bores are required to be shut-in from time to time due to a variety of issues, including a combination of weather, mechanical problems, sand production, bottom sediment, water and paraffin associated with our condensate production, as well as downstream third-party facility and pipeline shut-ins. In addition, shut-ins are necessary from time to time to upgrade and improve the production handling capacity at related downstream platform, gas processing and pipeline infrastructure. In addition to negatively impacting our near term revenues and cash flow, repeated production shut-ins may damage our well bores if repeated excessively or not executed properly. The loss of a well bore due to damage could require us to drill a replacement well, which could adversely affect our business, financial condition, results of operations and cash flows.

Natural gas and oil reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows will be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Furthermore, initial production rates in shale plays tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Additionally, the majority of our reserves are proved developed producing. Accordingly, we do not have significant opportunities to increase our production from our existing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

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

There are numerous uncertainties in estimating oil and natural gas reserves and their value, including many factors that are beyond our control. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves shown in this report.

In order to prepare these estimates, our independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves shown in a reserve report. In addition, estimates of our proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control and may prove to be incorrect over time. As a result, our estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in our reserve report have produced for a relatively short period of time. Accordingly, some of our reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect our financial condition, future prospects and market value. Moreover, failure to meet operating or financial forecasts and expectations, whether published by us or market participants, could adversely impact the trading price of our common stock.

Approximately 23% of our total estimated proved reserves at December 31, 2019 were proved undeveloped reserves. 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.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our oil, natural gas and natural gas liquids reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. 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.

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

You should not assume that the present value of future net revenues from our proved reserves referred to in this report is the current market value of our estimated oil, natural gas and natural gas liquids reserves. In accordance with the requirements of the SEC, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2019 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2019. For our condensate and natural gas liquids, the average West Texas Intermediate (Cushing) posted price was $55.69 per barrel, and the average Henry Hub spot price was $2.52 per MMBtu for natural gas, as prepared by Cobb. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our common stock. Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil, natural gas and natural gas liquids. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. However, even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. If exploratory drilling of a prospect, such as the well subject to our joint operating agreement with Juneau, is not successful, we may be required to incur additional expenditures relating to abandonment of the well, with no corresponding revenues. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

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

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for oil, natural gas and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- abnormal pressure formations, reservoir compaction, surface cratering or uncontrollable flows of underground natural gas, oil or formation water;
- pipe and cement failures, casing collapses, stuck drilling and service tools;
- explosions, fires and blowouts;
- environmental hazards, such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions and failures;
- unexpected operational events;
- shortages of skilled personnel and regulations or conditions that limit the availability of personnel to operate our business or assets;
- gathering, transportation and processing availability, restrictions or limitations;
- deviations from the desired drilling zone or not running casing or tools consistently through the wellbore, particularly as lateral lengths get longer;
- shortages or delivery delays of equipment and services or of water used in hydraulic fracturing activities;
- compliance with environmental and other regulatory requirements;
- stockholder activism and activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas so as to minimize emissions of GHGs;
- natural disasters; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, reservoirs, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume operations; suspension of our operations and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We carry limited environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

The potential lack of availability of, or cost of, drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

When the prices of oil, natural gas and natural gas liquids increase, or the demand for equipment and services is greater than the supply in certain areas, such as the Southern Delaware Basin, we typically encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operations and financial condition.

A sustained continuation of product transportation, processing and market constraints in the Southern Delaware Basin may adversely impact our results of operations and the value of our oil and gas properties in the region.

The Permian Basin, which includes the Southern Delaware Basin in which we have significant oil and gas properties, has been subject to significant product transportation and market constraints resulting from the increased drilling activity and consequent increased production of oil, natural gas and natural gas liquids in the region. One of the results of these constraints over the past several years is the development of significant negative field pricing differentials for Southern Delaware Basin oil, natural gas and natural gas liquids production when compared to prices at major domestic oil and natural gas product hubs. While extensive capital investments are being made to provide additional production transportation, natural gas processing and alternative markets in the region, there is no assurance as to when or if any of these additional midstream and alternative market projects might be made available to our production or at what cost. If these constraints and consequent pricing differentials continue unabated for a significant amount of time, the financial returns for oil and gas assets in the Southern Delaware Basin may be considerably devalued when compared to oil and gas investments in hydrocarbon producing regions with greater access to major hydrocarbon markets.

Production activities in the Gulf of Mexico increase our susceptibility to pollution and natural resource damage.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

Further, a blowout, rupture or spill of any magnitude would present serious operational and financial challenges. All of the Company’s operations in the Gulf of Mexico shelf are in water depths of less than 300 feet and less than 50 miles from the coast. Such proximity to the shore-line increases the probability of a biological impact or damaging the fragile eco-system in the event of released condensate.

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

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices and price differentials of oil, natural gas and natural gas liquids, as well as interest rates, we have, and may in the future, enter into over-the-counter (“OTC”) derivative arrangements for a portion of our oil, natural gas and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We typically utilize financial instruments to hedge commodity price exposure to declining prices on our oil, natural gas and natural gas liquids production. We typically use a combination of puts, swaps and costless collars.

Our production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

The enactment of derivatives legislation 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 Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) enacted in 2010, established federal oversight and regulation of the OTC derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position-limits rule was vacated by the U.S. District Court for the District of Columbia in September 2012. In November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions, but the rule was not adopted. In December 2016, the CFTC proposed another new version of the rule, but that too was not adopted. In February 2020, the CFTC proposed another version of its position limits rule that is currently pending at the agency. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing, and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or 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 currently 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 that we use for hedging. In addition, if any of our swaps did not qualify for the end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

The full impact of the various regulatory requirements will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. In addition, recently, proposals have been made by U.S. banking regulators which, if adopted as proposed, could significantly increase the capital requirements for certain participants in the OTC derivatives market in which we participate. The Dodd-Frank Act and regulations, such as the recently proposed increased capital requirements regulation, 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, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, 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. Increased volatility may make us less attractive to certain types of investors.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

If prices remain at current levels or decline further, we will likely incur further impairment of proved properties and experience a reduction in our proved undeveloped reserves.

During the year ended December 31, 2019, we recognized $117.8 million in non-cash impairment charges of proved properties due to reserve revisions. Included in that impairment charge was $34.5 million related to our proved offshore Gulf of Mexico properties, primarily a result of a reassessment of the future operating costs and a revision to the reservoir decline model for the expected decline in recoverable condensate volumes. In addition, we recognized onshore proved property impairment expense of $83.3 million, including $73.7 million in the Bullseye area in our West Texas region and $9.6 million in our Other Onshore region. The onshore impairment was primarily due to performance revisions and changes in realizable prices, which impacted the expected economics for proved undeveloped locations in these areas and led to the re-evaulation of the future drilling plans for the proved undeveloped locations. This resulted in the elimination of certain proved undeveloped locations due to the SEC's five year development rule for such locations.

If management's estimates of the recoverable proved reserves on a property are revised downward or if oil and/or natural gas prices decline further in 2020, we may be required to record additional non-cash impairment write-downs in the future, which would result in a negative impact to our financial results. Furthermore, any sustained decline in oil and/or natural gas prices may require us to make further impairments. We review our proved oil and gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and natural gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded cost basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value.

Management's assumptions used in calculating oil and gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as management's views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment. An impairment may have a material adverse effect on our financial results and the trading price of our common stock.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and may continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. While no comprehensive climate change legislation has been implemented to date at the federal level, the EPA and states and groupings of states have considered or pursued cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In particular, the EPA adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore and offshore oil and natural gas production facilities, which includes certain of our operations.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In 2016, the EPA published a final rule establishing 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. These Subpart OOOOa standards expand the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices. However, in 2017, the EPA published a proposed rule to stay certain portions of the 2016 standards for two years, but the EPA has not yet published a final rule. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule, and in September 2018 the EPA proposed additional amendments, including rescission of certain requirements and revisions to other requirements, such as fugitive emission monitoring frequency.

The EPA is in the process of finalizing these amendments, which it originally expected to do in late 2019. Separately, on August 28, 2019, the EPA proposed amendments to the 2012 and 2016 NSPS for the Oil and Natural Gas Industry that would remove all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS, both for ozone-forming VOCs, and for GHGs. The existing NSPS regulates GHGs through limitations on emissions of methane. The amendments also would rescind the methane requirements in the 2016 NSPS that apply to sources in the production and processing segments of the industry. As an alternative, the EPA also is proposing to rescind the methane requirements that apply to all sources in the oil and natural gas industry, without removing any sources from the current source category. In addition, in August 2019, the EPA issued the Affordable Clean Energy rule that designates heat rate improvement, or efficiency improvement, as the best system of emissions reduction for carbon dioxide from existing coal-fired electric utility generating units.

Furthermore, in late 2016, the BLM published a final rule to reduce methane emissions by regulating venting, flaring and leaks from oil and natural gas production activities on onshore federal and Native American lands. However, in September 2018, the BLM published a final rule that rescinds most of the new requirements of the 2016 final rule and codifies the BLM’s prior approach to venting and flaring, but the rule rescinding the 2016 final rule has been challenged in federal court and remains pending. These rules, should they remain or be placed in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our operations as well as result in restrictions, delays or cancellations in such operations, which costs, restrictions, delays or cancellations could adversely affect our business. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future international, federal or state laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, which could reduce the demand for the oil and natural gas we produce and lower the value of our reserves, which devaluation could be significant.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. 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. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. It should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. An increase in severe weather patterns could result in damages to or loss of our wells and related facilities, rig availability for drilling new or replacement wells, impact our ability to conduct our production and/or drilling operations and/or result in a disruption of the operations of our customers and service providers. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of GHGs emissions-related agreements, legislation and measures on our financial performance is highly uncertain because we are unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

Should we fail to comply with all applicable statutes, rules, regulations and orders of the FERC, the CFTC or the FTC, we could be subject to substantial penalties and fines.

Section 1(b) of the NGA exempts natural gas gathering facilities from the FERC’s jurisdiction. We believe that the gas gathering facilities we own meet the traditional tests the FERC has used to establish a pipeline system’s status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of our gathering facilities may be subject to change based on future determinations by the FERC and the courts. Our failure to comply with this or other laws and regulations administered by the FERC could subject us to substantial penalties, as described in Part I, Item 1: "Business—Governmental Regulations and Industry Matters."

Under the 2005 Act and implementing regulations, the FERC prohibits market manipulation in connection with the purchase or sale of natural gas. The CFTC has similar authority under the Commodity Exchange Act and regulations it has promulgated thereunder with respect to certain segments of the physical and futures energy commodities market including oil and natural gas. The FTC also prohibits manipulative or fraudulent conduct in the wholesale petroleum market with respect to sales of commodities, including oil, condensate and natural gas liquids. These agencies have substantial enforcement authority, including the potential ability to impose maximum penalties for violations in excess of $1 million per day for each violation. Following their adoption, the maximum penalties prescribed by these regulations have been subject to annual adjustment for inflation. The FERC has also imposed requirements related to reporting of natural gas sales volumes that may impact the formation of prices indices. Additional rules and legislation pertaining to these and other matters may be considered or adopted from time to time. In addition, we rely on our employees, consultants and sub-contractors to conduct our operations in compliance with applicable laws and standards. Our failure, or the failure by such individuals, to comply with these or other laws and regulations administered by these agencies could subject us to substantial penalties, and potential liability as described in Part I, Item 1: "Business—Governmental Regulations and Industry Matters."

Our ability to market our natural gas and oil may be impaired by capacity constraints and equipment malfunctions on the platforms, gathering systems, pipelines and gas plants that transport and process our natural gas and oil.

All of our natural gas and oil is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or our transportation capacity is materially restricted or is unavailable in the future, our ability to market our natural gas or oil could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on our financial condition and results of operations. Further, repeated shut-ins of our wells could result in damage to our well bores that would impair our ability to produce from these wells and could result in additional wells being required to produce our reserves.

If our access to sales markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory oil, natural gas and natural gas liquids transportation arrangements may hinder our access to oil, natural gas and natural gas liquids markets or delay our production. The availability of a ready market for our oil, natural gas and natural gas liquids production depends on a number of factors, including the demand for and supply of oil, natural gas and natural gas liquids and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil, natural gas and natural gas liquids may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

We may not have title to our leased interests and if any lease is later rendered invalid, we may not be able to proceed with our exploration and development of the lease site.

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is to not incur the expense of retaining title lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of consultants and others to perform the field work in examining records in the appropriate governmental, county or parish clerk's office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to the drilling of an exploration well, the operator of the well will typically obtain a preliminary title review of the drill site lease and/or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. However, such deficiencies may not have been cured by the operator of such wells. It does happen, from time to time, that the examination made by title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect. It may also happen, from time to time, that the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion.

Competition in the natural gas and oil industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with a broad range of natural gas and oil companies in our exploration and property acquisition activities. We also compete for the equipment and labor required to operate and to develop these properties. Many of our competitors have substantially greater financial resources than we do. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties. Further, they may be able to evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil and to acquire additional properties in the future depends on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating for a much longer time than we have and have substantially larger staffs. We may not be able to compete effectively with these companies or in such a highly competitive environment.

We may not be able to utilize a portion of our net operating loss carryforwards ("NOLs") to offset future taxable income for U.S. federal income tax purposes, which could adversely affect our net income and cash flows.

As of December 31, 2018, we had federal net operating loss ("NOL") carryforwards of approximately $365.5 million, approximately $287.3 million of which began to expire in 2018 and will continue to expire in varying amounts through 2037. Utilization of these NOLs depends on many factors, including our future taxable income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), generally imposes an annual limitation on the amount of an NOL that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382 of the Code). An ownership change generally occurs if one or more shareholders (or groups of shareholders) who are each deemed to own at least 5 percent of the corporation's stock increase their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change occurs with respect to a corporation following its recognition of an NOL, utilization of such NOL is subject to an annual limitation, generally determined by multiplying the value of the corporation's stock at the time of the ownership change by the applicable long-term tax-exempt rate. However, this annual limitation would be increased under certain circumstances by recognized built-in gains of the corporation existing at the time of the ownership change. In the case of an NOL that arose in a taxable year beginning before January 1, 2018, any unused annual limitation with respect to an NOL generally may be carried over to later years, subject to the expiration of such NOL 20 years after it arose.

As a result of our recent stock offerings, combined with ownership shifts over the rolling three-year period, we have incurred ownership changes on each of November 19, 2018 and September 12, 2019 pursuant to Section 382, which limits the Company's future ability to use its NOLs. To the extent we are unable to utilize our NOLs to offset future income or carryback our NOLs to apply against prior tax years, we will be limited in use of NOLs for amounts incurred prior to November 20, 2018 in an amount equal to $2.4 million per year (plus any recognized built in gains during the next five years) or until expiration of each annual vintage of NOL (generally, 20 years for each annual vintage of NOLs incurred prior to 2018). However, the September 2019 ownership change resulted in an annual limitation of approximately $700 thousand per year, which has the effect of limiting tax attribute usage from the 2018 ownership change in a similar manner and amount. Due to the presence of the valuation allowance from prior years, this event resulted in a no net charge to earnings. Future changes in our stock ownership or future regulatory changes could also limit our ability to utilize our NOLs. To the extent we are not able to offset future taxable income with our NOLs, our net income and cash flows may be adversely affected.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated. Additional state taxes on oil and natural gas extraction may be imposed, as a result of future legislation.

From time to time, U.S. lawmakers propose certain changes to U.S. tax laws applicable to oil and natural gas companies. These changes include, but are not limited to: (i) the elimination of current deductions for intangible drilling and development costs; (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes (or the imposition of, or increases in, production, severance or similar taxes) were to be enacted, as well as any similar changes in state, local or non-U.S. law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas.

We are subject to stringent environmental laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Our oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing the operation and maintenance of our facilities, the discharge of materials into the environment and environmental protection. Failure to comply with such rules and regulations could result in the assessment of sanctions, including administrative, civil and criminal penalties, investigatory, remedial and corrective action obligations, the occurrence of delays, cancellations or restrictions in permitting or performance of projects and the issuance of orders limiting or prohibiting some or all of our operations in affected areas. These laws and regulations may require that we obtain permits before commencing drilling or other regulated activities; restrict the substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on protected areas, such as wetlands or wilderness areas; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and impose substantial penalties for pollution resulting from drilling and production operations. We maintain insurance coverage for sudden and accidental environmental damages; however, it is possible that coverage might not be sufficient in a catastrophic event. Consequently, we could be exposed to liabilities for cleanup costs, natural resource damages and other damages under these laws and regulations, with certain of these legal requirements imposing strict liability for such damages and costs, even though the conduct in pursuing operations was lawful at the time it occurred or the conduct resulting in such damage and costs were caused by prior operators or other third-parties.

Environmental laws and regulations in the United States are subject to change in the future, possibly resulting in more stringent legal requirements. If existing environmental regulatory requirements or enforcement policies change or new regulatory or enforcement initiatives are developed and implemented in the future, we may be required to make significant, unanticipated capital and operating expenditures with respect to the continued operations of the drilling program. Examples of recent environmental regulations include the following:

- *Federal Jurisdiction over Waters of the United States*. As a result of the legal developments described in further detail in "Governmental Regulation and Industry Matters, *Environmental and Occupation Health and Safety Matters*," future implementation of the WOTUS 2015 rule or a revised rule is uncertain at this time. To the extent that the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where we conduct operations, we could incur increased costs and restrictions, delays or cancellations in permitting or projects, which developments could expose us to significant costs and liabilities.

Compliance of our operations with these regulations or other laws, regulations and regulatory initiatives, or any other new environmental and occupational health and safety legal requirements could, among other things, require us to install new or modified emission controls on equipment or processes, incur longer permitting timelines, and incur significantly increased capital or operating expenditures, which costs may be significant. Moreover, any failure of our operations to comply with applicable environmental laws and regulations may result in governmental authorities taking actions against us that could adversely impact our operations and financial condition.

An accidental release of pollutants into the environment may cause us to incur significant costs and liabilities.

We may incur significant environmental cost liabilities in our business as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and waste water discharges related to our operations, and due to historical industry operations and waste disposal practices. We currently own, operate or lease numerous properties that for many years have been used for the exploration and production of oil and natural gas. Many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. For example, an accidental release resulting from the drilling of a well, could subject us to substantial liabilities arising from environmental cleanup, restoration costs and natural resource damages, claims made by neighboring landowners and other third parties for personal injury and property and natural resource damages as well as monetary fines or penalties for related violations of environmental laws or regulations. Moreover, certain environmental statutes impose strict, joint and several liability for these costs and liabilities without regard to fault or the legality of our conduct. Under these environmental laws and regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging or other decommissioning activities to prevent future contamination. We may not be able to recover some or any of these costs from insurance.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand or other proppant and chemical additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or similar state agencies, but several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the process. For example, the EPA has asserted regulatory authority pursuant to the SDWA Underground Injection Control program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities, as well as published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. The EPA also published final rules under the CAA in 2012 and in 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing. Additionally, in 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The BLM also published a final rule in 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands but the BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM’s decision to rescind the 2015 rule is pending in federal district court. Also, 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, including as a result of water withdrawals for fracturing in times or areas of low water availability or due to surface spills during the management of fracturing fluids, chemicals or produced water.

Moreover, from time to time, Congress has considered, but not enacted, legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, certain states, including Texas and Wyoming, where we conduct operations, have adopted and other states are considering adopting legal requirements that could impose new or more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. Additionally, non-governmental organizations may seek to restrict hydraulic fracturing, as has been the case in Colorado in recent years, when certain interest groups therein have unsuccessfully pursued ballot initiatives in recent general election cycles that, had they been successful, would have revised the state constitution or state statutes in a manner that would have made exploration and production activities in the state more difficult or costly in the future including, for example, by increasing mandatory setback distances of oil and natural gas operations, including hydraulic fracturing, from specific occupied structures and/or certain environmentally sensitive or recreational areas. Some counties have since 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. Hydraulic fracturing operators in Oklahoma have also been subject to lawsuits alleging that their fracturing activities caused a series of earthquakes in the past several years and that these operators are therefore liable for certain damages caused by the earthquakes. Such lawsuits could cause us to incur liabilities for damages caused by earthquakes or otherwise impact the profitability of our operations in Oklahoma.

In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we could incur potentially significant added costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells. Expectations or uncertainties regarding such restrictions being imposed (whether through the Executive Branch or by statute) could lead to increased volatility in our business plan and in the market price of our common stock.

We may be subject to additional supplemental bonding under the BOEM financial assurance requirements.

Energy companies conducting oil and natural gas lease operations offshore on the OCS are required by the BSEE, among other obligations, to conduct decommissioning within specified times following cessation of offshore producing activities, which decommissioning includes the plugging of wells, removal of platforms and other facilities and the clearing of obstacles from the lease site sea floor. To cover a lease operator's decommissioning obligations, the BOEM generally requires that lessees demonstrate financial strength and reliability according to regulations or otherwise post bonds or other acceptable financial assurances that such future obligations will be satisfied. As an operator, we are required to post surety bonds of $200,000 per individual lease (or a $1,000,000 area-wide bond) for exploration and $500,000 per lease for developmental activities as part of our general bonding requirements, as well as the posting of additional supplemental bonds to cover, among other things, our decommissioning obligations. We typically post surety bonds with the BOEM to satisfy our general and supplemental bonding requirements.

The BOEM continues to re-consider the adoption, implementation or enforcement of more stringent financial assurance regulatory initiatives, as well as more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters, all of which could result in additional costs, delays, restrictions, or obligations with respect to oil and natural gas exploration and production operations conducted offshore on the federal OCS. In particular, the BOEM issued NTL #2016-N01 that became effective in September 2016 and bolsters the financial assurance requirements offshore lessees on the OCS, including the Gulf of Mexico, must satisfy with respect to their decommissioning obligations. If the BOEM determines under NTL #2016-N01 that a company does not satisfy the minimum requirements to qualify for providing self-insurance to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. However, in 2017, the Secretary of the U.S. Department of Interior issued Order 3350 ("Order 3350"), which directed the BOEM and the BSEE to reconsider a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities, including, for example, NTL #2016-N01, and provide recommendations on whether such regulatory initiatives should continue to be implemented. As a result, the BOEM extended the start date for implementing NTL #2016-N01 indefinitely beyond June 30, 2017. This extension currently remains in effect; however, the BOEM reserved the right to re-issue liability orders in the future, including in the event that it determines there is a substantial risk of nonperformance of the interest holder's decommissioning obligations. Following completion of its review, the BOEM may elect to retain NTL #2016-N01 in its current form or may make revisions thereto and, thus, until the review is completed and the BOEM determines what additional financial assurance may be required by us, we cannot provide assurance that such financial assurance coverage can be obtained. Moreover, the BOEM could in the future make other demands for additional financial assurances covering our obligations under sole liability properties and/or non-sole liability properties.

If we fail to comply with any orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, ordering suspension of operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition. Moreover, under existing BOEM rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interest may be held jointly and severally liable for decommissioning obligations at those OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee or any subsequent assignee is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BOEM to decommission OCS facilities that one of our assignees or any subsequent assignee of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, which costs could be material.

The BSEE has implemented stringent controls and reporting requirements that if not followed, could result in significant monetary penalties or a shut-in of all or a portion of our Gulf of Mexico operations.

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. Over the past decade, the agency has been responsible for leading aggressive and comprehensive reforms regarding regulation and oversight of the offshore oil and natural gas industry. These reforms have resulted in more stringent offshore requirements including, for example, well and blowout preventer design, workplace safety and corporate accountability. However, as a result of the issuance of Order 3350 in 2017, the BSEE continues to reconsider certain regulations or regulatory initiatives governing offshore oil and gas safety and performance-related activities. For example, in December 2017, the BSEE proposed, and in September 2018 it finalized, revisions to its regulations regarding offshore drilling safety equipment, which revisions include the removal of an obligation for offshore operators to certify through an independent third party that their critical safety and pollution prevention equipment (e.g., subsea safety equipment, including blowout preventers) is operational and functioning as designed in the most extreme conditions. Subsequently, on May 2, 2019, BSEE issued the 2019 Well Control Rule, the revised well control and blowout preventer rule governing Outer Continental Shelf (OCS) activities. The new rule revised the then existing regulations impacting offshore oil and gas drilling, completions, workovers, and decommissioning activities. Specifically, the 2019 Well Control Rule addresses six areas of offshore operations: well design, well control, casing, cementing, real-time monitoring and subsea containment. The revisions were targeted to ensure safety and environmental protection while correcting errors in the 2016 rule and reducing unnecessary regulatory burden.

Additionally, the Outer Continental Shelf Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and periodic unscheduled (unannounced) inspections of all oil and natural gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production and pipeline safety. Upon detecting an alleged violation, the inspector typically issues an Incident of Noncompliance ("INC") to the operator that, depending on the severity of such violation, either serves as a warning to address such violation or requires a shut-in of a facility component or of the entire facility until such time as the violation is corrected. The warning INC is issued for a less severe or threatened condition and must be corrected within a reasonable amount of time, as specified on the INC, whereas the shut-in INC is for more serious conditions that must be corrected before the operator is allowed to resume the activity in question.

In addition to the enforcement actions specified above, the BSEE can assess civil penalties if: (i) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or (ii) the violation resulted in a threat of serious harm or damage to human life or the environment. In January 2018, the BSEE published a final rule that increased the maximum civil penalty rate for Outer Continental Shelf Lands Act violations to $43,576 a day for each violation. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

We are highly dependent on our senior management team, our exploration partners, third-party consultants and engineers and other key personnel, and any failure to retain the services of such parties could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy is highly dependent on our management team, as well as certain key geoscientists, geologists, engineers and other professionals engaged by us. The loss of key members of our management team or other highly qualified technical professionals could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies which may have a material adverse effect on our business, financial condition and operating results. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel, particularly in our new geographic areas such as Oklahoma. Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

We expect to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties or businesses requires an assessment of:

- Recoverable reserves.

- Exploration potential.
- Future natural gas and oil prices.
- Operating costs.
- Potential environmental and other liabilities and other factors.
- Permitting and other authorizations, including environmental permits and authorizations, required for our operations.
- Impact on leverage and access to capital.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are necessarily inexact and their accuracy inherently uncertain and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Future acquisitions could pose additional risks to our operations and financial results, including:

- Problems integrating the purchased operations, personnel or technologies.
- Unanticipated costs.
- Diversion of resources and management attention from our exploration business.
- Entry into regions or markets in which we have limited or no prior experience.
- Potential loss of key employees of the acquired organization.
- Dilution from issuance of new equity.
- Increased capital commitments or leverage.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing oil, natural gas and natural gas liquids properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing oil, natural gas and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

With our recent acquisitions of certain producing assets and undeveloped acreage in Oklahoma and continued growth in the Southern Delaware Basin, we continue to operate in relatively new areas of exploration and development in which we have limited experience and facilities, and as a result we may experience inefficiencies, incur unanticipated or higher costs and expenses, or may not fully realize the benefits anticipated. We may be unable to successfully integrate the newly acquired properties with our existing operations.

We have a limited operating history in West Texas and Oklahoma. As a result, we will need to continue to integrate the properties and operations relating thereto with our current oil and gas operations, which may increase the risk of inefficiencies in timing, coordination and staffing, unanticipated higher costs and expenses than we currently have projected or drilling results below our expectations. As a result, any desired benefits in these areas may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted. The difficulties of integrating these assets and properties present numerous risks, including:

- Acquisitions may prove unprofitable and fail to generate anticipated cash flows or meet drilling expectations.
- We may need to (i) recruit additional personnel, and we cannot be certain that any of our recruiting efforts will succeed and (ii) expand corporate infrastructure to facilitate the integration of our operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses or distract our management.
- Our management's attention may be diverted from other business concerns and we may risk inefficiencies in timing and coordination.
- We may encounter unanticipated higher costs and expenses than we currently have projected.

We are also exposed to risks that are commonly associated with acquisitions of this type, such as unanticipated liabilities and costs, some of which may be material. Failure to timely and successfully integrate these assets and properties with our operations may have a material adverse effect on our business, financial condition and result of operations.

Increases in interest rates could adversely impact our business, share price and our ability to issue equity or incur debt for acquisitions, capital expenditures or other purposes.

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Rising interest rates could reduce the amount of cash we generate and materially adversely affect our liquidity. Moreover, the trading price of our common stock is sensitive to changes in interest rates and could be materially adversely affected by any increase in interest rates.

Assuming an outstanding balance on our Credit Agreement of $72.8 million, an increase of one percentage point in the interest rates would have resulted in an increase in interest expense during 2019 of $0.7 million. Accordingly, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates.

Cybersecurity breaches and information technology failures could harm our business by increasing our costs and negatively impacting our operations.

We rely extensively on information technology systems, including Internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of evolving cybersecurity risks, such as those involving unauthorized access or control, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks, ransomware and other security issues. Moreover, cybersecurity threat actors, whether internal or external to us, are becoming more sophisticated and coordinated in their attempts to access a company's information technology systems and data, including the information technology systems of cloud providers and other third parties with whom companies conduct business.

Although we have implemented information technology controls and systems that are designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the enhanced controls we have installed may be breached. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations which may include drilling, completion, production and corporate functions. A cyber attack involving our information systems and related infrastructure, or that of our business associates, including key customers and suppliers, could negatively impact our operations in a variety of ways, including but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

- Data corruption, communication interruption or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;
- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;
- A cyber attack on third party gathering, pipeline or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices and reduced revenues;
- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;
- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and
- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's or landowner's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

All of the above could negatively impact our operational and financial results. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for and supply of oil, natural gas and natural gas liquids, domestically and globally;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;

- general market, economic and political conditions, domestically and globally;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us, our significant stockholders or members of our management team; and
- natural disasters, pandemics, terrorist attacks and acts of war.

Average natural gas and oil prices declined dramatically beginning in early 2015 and have remained relatively low since then. In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This decline in commodity prices and stock market volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

We are a smaller reporting company and we cannot be certain if the reduced disclosure requirements applicable to smaller reporting companies will make our common stock less attractive to investors.

The SEC adopted amendments to the definition of "smaller reporting company" that became effective in September 2018. Under the new definition a company generally qualifies as a smaller reporting company if it has (1) a public float of less than $250 million or (2) annual revenues of less than $100 million during the most recently completed fiscal year and either (A) no public float or (B) a public float of less than $700 million. Public float is measured as of the last business day of the most recently completed second fiscal quarter. As a result of such amendments, we qualified as a "smaller reporting company" for the fiscal years ended December 31, 2019 and 2018. As a "smaller reporting company," we are subject to reduced disclosure obligations in our SEC filings compared to other issuers, including, among other things, an exemption from the requirement to present five years of selected financial data and being subject to simplified executive compensation disclosures. Until such time as we cease to be a "smaller reporting company," such reduced disclosure in our SEC filings may make it harder for investors to analyze our operating results and financial prospects. If some investors find our common stock less attractive as a result of any choices to reduce disclosure we may make, there may be a less active trading market for our common stock and our stock price may be more volatile.

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Also, the provisions of our Credit Agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

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

Our board of directors is authorized, without further stockholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series. We are authorized to issue up to five million shares of preferred stock. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we issued three series of preferred stock in 2019. The Series A and Series B preferred stock, which converted into common stock in December 2019, had the right to vote with holders of our common stock on an as-converted basis. The outstanding Series C preferred stock is not entitled to vote except as otherwise provided by law. Also, 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.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of December 31, 2019, we had 20,964 stock options to purchase shares of our common stock outstanding, all of which were fully vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our bylaws provide certain limitations with respect to business combinations with affiliated stockholders, which may discourage transactions that would otherwise be preferred by a stockholder.

We have elected not to be governed by Texas business combination law, which prohibits a publicly held Texas corporation from engaging in a business combination with an affiliated shareholder for a period of three years after the affiliated shareholder's share acquisition date, unless the business combination is approved in a prescribed manner. Our bylaws, however, provide that, subject to certain exceptions, we shall not engage in any business combination (as defined in our bylaws) with any "affiliated stockholder" for a period of three years following the time that such stockholder became an affiliated stockholder, unless:

- prior to such time, our board of directors approved either the business combination or the transaction which resulted in the stockholder becoming an affiliated stockholder;

- upon consummation of the transaction which resulted in the stockholder becoming an affiliated stockholder, the affiliated stockholder owned at least 85% of our voting common stock outstanding, excluding shares held by certain directors who are also officers;

- at or subsequent to such time, the business combination is approved by the affirmative vote of (i) our board of directors and (ii) the holders of at least two-thirds (2/3) of our outstanding voting common stock not owned by the affiliated stockholder or an affiliate or associate of the affiliated stockholder, at a meeting of stockholders called for that purpose not less than six months after the transaction which resulted in the stockholder becoming an affiliated stockholder; or

- at or subsequent to such time, the business combination is approved by (i) a majority of the directors of our board who are not the affiliated stockholder (or an affiliate or associate thereof, or nominated for election by such affiliated stockholder) and were a member of our board on or prior to June 14, 2019 or were elected or nominated for election by a majority of directors who were members of our board on or prior to June 14, 2019, and (ii) a majority of our voting common stock outstanding.

For purposes of this provision, "affiliated stockholder" means any person that is the owner of 20% or more of the voting common stock outstanding or, during the preceding three-year period, was the owner of 20% or more of our voting common stock outstanding; provided, however, that "affiliated stockholder" does not include certain stockholders whose aggregate ownership does not exceed 23% of our voting common stock outstanding, subject to adjustment by our board of directors. This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. This provision may also have the effect of limiting financing transactions with interested stockholders that could be deemed favorable sources of capital. With the approval of 2/3 of our board of directors or our stockholders, this provision of our bylaws could be amended to further provide antitakeover protection. In addition, with approval of our board of directors and a majority of stockholders, we could change our state of incorporation and modify the antitakeover provisions applicable to us, or we could amend our certificate of incorporation in the future to elect to be governed by the Texas business combination law.

Certain antitakeover provisions may affect your rights as a shareholder.

Our articles of incorporation authorize our board of directors to set the terms of and issue preferred stock without shareholder approval. Our board of directors could use the preferred stock as a means to delay, defer or prevent a takeover attempt that a shareholder might consider to be in our best interest. In addition, our revolving credit facility and our indentures governing our senior notes and our outstanding preferred stock contain terms that may restrict our ability to enter into change of control transactions, including requirements to repay borrowings under our revolving credit facility, to offer to repurchase senior notes and to offer to redeem our preferred stock in either event upon a change of control, as determined under the relevant documents relating to such obligations. These provisions, along with specified provisions of the TBOC and our articles of incorporation and bylaws, may discourage or impede transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock.

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

None

Item 2. ***Properties***

As of December 31, 2019, we operated all of our offshore wells, with an average working interest of 54%, and operated 69% of our onshore wells with an average working interest of 77.7%. As of December 31, 2019, our properties were located in the following regions: Offshore Gulf of Mexico, Western Anadarko, Central Oklahoma, West Texas and Other Onshore.

Development, Exploration and Acquisition Expenditures

The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties, exploration costs incurred in the search for new reserves from unproved properties and costs incurred in the development of those properties for the periods indicated (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Property acquisition costs:			
Unproved	$ 12,486	$ 10,339	$ 6,540
Proved	168,838	—	—
Exploration costs	1,003	1,637	8,158
Development costs	41,273	42,516	45,016
Total costs	$ 223,600	$ 54,492	$ 59,714

Included in proved property acquisition costs for the year ended December 31, 2019 are those related to the Will Energy and White Star acquisitions. See Note 4 – “Acquisitions and Dispositions” for more information.

Unproved property acquisition costs for the year ended December 31, 2019 include $6.0 million related to our offshore Joint Development Agreement with Juneau and $3.1 million related to the properties acquired in the Will Energy and White Star acquisitions. Included in unproved property acquisition costs for each of the years ended December 31, 2019, 2018 and 2017 is $2.7 million, $10.2 million and $5.9 million, respectively, related to the acquisition of unproved property in the Southern Delaware Basin.

The following table presents information regarding our share of the net costs incurred by Exaro in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated (in thousands):

	Year Ended December 31,		
	2019	2018	2017
Property acquisition costs	$ —	$ —	$ —
Exploration costs	17	—	—
Development costs	72	169	429
Total costs incurred	$ 89	$ 169	$ 429

Drilling Activity

The following tables show our exploratory and developmental drilling activity for the periods indicated. In the tables, "gross" wells refer to wells in which we have a working interest, and "net" wells refer to gross wells multiplied by our working interest in such wells.

	Year Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	—	—	—	—	1	0.5
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	1	0.4
Non-productive (offshore)	—	—	—	—	—	—
Total	—	—	—	—	2	0.9

	Year Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive (onshore)	7	3.0	8	3.6	4	1.9
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	7	3.0	8	3.6	4	1.9

As of December 31, 2019, we had one drilled but uncompleted onshore development well. We have a 25 percent working interest in the well, which began producing in January 2020.

Exploration and Development Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of oil, natural gas and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres.

The following table shows the approximate developed and undeveloped acreage that we have an interest in, by region, at December 31, 2019.

	Developed Acreage (1)		Undeveloped Acreage (1)	
	Gross	Net (2)	Gross	Net (2)
Offshore GOM	4,213	2,281	—	—
Central Oklahoma	569,034	248,119	174,720	38,550
Western Anadarko	274,397	157,878	28,800	9,272
West Texas	14,790	6,920	3,815	1,079
Other Onshore[3]	58,625	33,126	51,914	33,470
Total	921,059	448,323	259,249	82,371

(1) Excludes any interest in acreage in which we have no working interest before payout or before initial production.
(2) Net acres represent the number of acres attributable to our proportionate working interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).
(3) Other Onshore includes acreage in East, South and Southeast Texas, Louisiana, Wyoming and Mississippi.

Some of our onshore leases will expire over the next three years as follows, unless we establish production or take action to extend the terms of these leases:

	Year ending December 31,					
	2020		2021		2022	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Central Oklahoma	148,480	24,807	43,520	11,300	17,280	1,351
Western Anadarko	17,920	5,454	21,760	3,776	2,560	42
West Texas	909	454	650	315	7	4
Other Onshore	7,898	5,031	17,621	14,097	2,182	1,745
Total	175,207	35,746	83,551	29,488	22,029	3,142

Production, Price and Cost History

The table below sets forth production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the years ended December 31, 2019, 2018 and 2017. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six Mcf of natural gas. Average production costs include lease operating expense, transportation and processing costs and workover costs.

	Year Ended December 31,		
	2019	**2018**	**2017**
Production:			
Oil and condensate (thousand barrels)			
Offshore GOM	43	73	99
Central Oklahoma	196	—	—
Western Anadarko	42	—	—
West Texas	275	275	133
Other Onshore	235	221	286
Total oil and condensate	791	569	518
Natural gas (million cubic feet)			
Offshore GOM	5,908	7,704	11,189
Central Oklahoma	1,839	—	—
Western Anadarko	552	—	—
West Texas	320	285	82
Other Onshore	904	1,790	2,639
Total natural gas	9,523	9,779	13,910
Natural gas liquids (thousand barrels)			
Offshore GOM	210	287	330
Central Oklahoma	242	—	—
Western Anadarko	23	—	—
West Texas	64	59	12
Other Onshore	73	128	175
Total natural gas liquids	612	474	517
Total (million cubic feet equivalent)			
Offshore GOM	7,424	9,865	13,762
Central Oklahoma	4,466	—	—
Western Anadarko	941	—	—
West Texas	2,350	2,294	947
Other Onshore	2,759	3,880	5,414
Total production	17,940	16,039	20,123
Average Sales Price:			
Oil and condensate (per barrel)			
Offshore GOM	$ 59.68	$ 67.59	$ 49.95
Central Oklahoma	58.95	—	—
Western Anadarko	56.58	—	—
West Texas	51.36	54.52	47.76
Other Onshore	60.04	65.42	49.07
Total weighted average price	$ 56.55	$ 60.43	$ 48.90
Natural gas (per thousand cubic feet)			
Offshore GOM	$ 2.64	$ 3.14	$ 2.99
Central Oklahoma	1.92	—	—
Western Anadarko	1.77	—	—
West Texas	0.78	1.87	2.81
Other Onshore	2.21	2.87	2.91
Total weighted average price	$ 2.35	$ 3.05	$ 2.97

	Year Ended December 31,		
	2019	2018	2017
Natural gas liquids (per barrel)			
Offshore GOM	$ 17.09	$ 29.48	$ 26.78
Central Oklahoma	14.66	—	—
Western Anadarko	11.92	—	—
West Texas	14.77	25.55	18.93
Other Onshore	14.57	22.22	16.09
Total weighted average price	$ 15.39	$ 27.04	$ 22.97
Total (per thousand cubic feet equivalent)			
Offshore GOM	$ 2.93	$ 3.81	$ 3.43
Central Oklahoma	4.18	—	—
Western Anadarko	3.85	—	—
West Texas	6.51	7.44	7.16
Other Onshore	6.23	5.78	4.54
Total weighted average price	$ 4.26	$ 4.80	$ 3.90
Average Production Costs (per thousand cubic feet equivalent):			
Offshore GOM	$ 0.85	$ 0.84	$ 0.72
Central Oklahoma	2.07	-	-
Western Anadarko	1.89	-	-
West Texas	1.86	1.10	1.50
Other Onshore	2.86	3.01	2.46
Total average production costs	$ 1.65	$ 1.40	$ 1.22

Productive Wells

Productive wells are producing wells and wells capable of producing commercial quantities. Completed but marginally producing wells are not considered here as a "productive" well. The following table sets forth the number of gross and net productive natural gas and oil wells in which we owned an interest as of December 31, 2019:

	Natural Gas Wells		Oil Wells	
	Gross Wells (1)	Net Wells (2)	Gross Wells (1)	Net Wells (2)
Offshore GOM	7	3.8	—	—
Central Oklahoma	68	28.6	710	420.9
Western Anadarko	458	293.6	134	55.2
West Texas	—	—	17	8.2
Other Onshore	51	28.2	97	60.7
Total	584	354.2	958	545.0

(1) A gross well is a well in which we own an interest.

(2) The number of net wells is the sum of our fractional working interests owned in gross wells.

Throughput Contract Commitment

The Company has a throughput agreement with a third party pipeline owner/operator through March 31, 2020. See Note 14 – "Commitments and Contingencies" for further information.

Natural Gas and Oil Reserves

Estimates of proved reserves and future net revenues were prepared by Cobb and Netherland, Sewell & Associates, Inc. ("NSAI"), our independent petroleum engineering firms, in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE"). Cobb prepared the proved reserves estimates as of December 31, 2019 for all of our properties. For the estimates of proved reserves as of December 31, 2018, Cobb prepared the estimates for all of our offshore Gulf of Mexico properties and our onshore West Texas reserves, while NSAI prepared the proved reserves estimates for our remaining onshore properties.

The technical individual at Cobb responsible for overseeing the preparation of our reserve estimates as of December 31, 2019 and 2018 has over 40 years of experience in the estimation and evaluation of reserves; is a registered professional engineer in the state of Texas, holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University, is a member of the SPE and is a member of the Society of Petroleum Evaluation Engineers. The technical individual at NSAI responsible for the preparation of our reserve estimates as of December 31, 2018 has over 15 years of experience in the estimation and evaluation of reserves, is a licensed professional engineer in the state of Texas, and holds a Bachelor of Science Degree in Petroleum Engineering from the University of Tulsa.

The estimates of proved reserves and future net revenue as of December 31, 2019 and 2018 were reviewed by our corporate reservoir engineering department. The corporate reservoir engineering department interacts with the geoscience, operating, accounting and marketing departments to review the integrity, accuracy and timeliness of the data, and the methods and assumptions used by Cobb and NSAI in the preparation of the reserves estimates. All relevant data is compiled in a computer database application to which only authorized personnel are given access rights. Our Reservoir Engineering Director is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for reviewing any reserves estimates prepared by our independent petroleum engineering firms. Our Reservoir Engineering Director has a Bachelor of Science degree in Petroleum Engineering from Texas Tech University, is a licensed professional engineer in the state of Texas, has over 15 years of industry experience with positions of increasing responsibility and is a member of the Society of Petroleum Engineers. She reports directly to our President and Chief Executive Officer. Reserves are also reviewed internally with senior management and presented to our board of directors in summary form on a quarterly basis.

We maintain adequate and effective internal control over the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of financial data, ownership interests and production data. Our reservoir engineers incorporate material changes in performance, activity and other inputs from operations, geology, land, or other departments, to reserve forecasts on a quarterly basis. The reservoir engineering team shares these changes with our independent petroleum engineering firm annually. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own internal control over financial reporting. Internal control over financial reporting is assessed for effectiveness annually using criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All data such as commodity prices, lease operating expenses, production taxes, field level commodity price differentials, ownership percentages and well production data are updated in the reserve database by our third-party reservoir engineers and then analyzed by management to ensure that they have been entered accurately and that all updates are complete. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firms prepare their independent reserve estimates and final report.

The following table reflects our estimated proved reserves as of the dates indicated:

	December 31, 2019	December 31, 2018
Crude Oil and Condensate (MBbl) [(1)]		
Developed	9,819	3,103
Undeveloped	9,266	6,331
Total	19,085	9,434
Natural Gas (MMcf) [(1)]		
Developed	122,691	46,840
Undeveloped	8,609	7,366
Total	131,300	54,206
Natural Gas Liquids (MBbl) [(1)]		
Developed	10,484	2,297
Undeveloped	1,280	1,220
Total	11,764	3,517
Total MMcfe		
Developed	244,515	79,234
Undeveloped	71,874	52,677
Total [(2)]	316,389	131,911
Proved developed reserves percentage	77 %	60 %
Standardized measure *(in thousands)*	$ 257,842	$ 218,944
Prices realized in estimates [(3)]:		
Crude oil ($/Bbl)	$ 53.98	$ 62.90
Natural gas ($/MMBtu)	$ 2.17	$ 3.02
Natural gas liquids ($/Bbl)	$ 16.95	$ 27.89

(1) Excludes reserves attributable to our 37% equity investment in Exaro.

(2) During the year ended December 31, 2019, total proved reserves increased by approximately 184.5 Bcfe primarily due to the 192.7 Bcfe increase related to the White Star and Will Energy acquisitions and an increase of 71.5 Bcfe in total reserves related to our recently drilled wells in the NE Bullseye area of West Texas and new PUD locations in our Other Onshore area, offset by a downward revision of 49.1 Bcfe primarily related to a reduction in Bullseye PUDs in West Texas in this low price environment and 2019 production of 17.9 Bcfe.

(3) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). 2019 SEC prices were $55.69 per bbl of oil and $2.25 per Mmbtu of natural gas. 2018 SEC prices were $64.80 per bbl of oil and $3.10 per Mmbtu of natural gas. Prices for natural gas liquids in the table represent average prices for natural gas liquids resulting from the proved reserve estimates, calculated in accordance with applicable SEC rules. All prices were adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves, and those realized prices, as averaged across all proved reserves, are presented in the table.

PV-10

PV-10 at year-end is a non-GAAP financial measure and represents the present value, discounted at 10% per year, of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure of Discounted Net Cash Flows represents an estimate of fair market value of our natural gas and oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure to PV-10 (in thousands):

	December 31, 2019	December 31, 2018
Standardized measure of discounted future net cash flows	$ 257,842	$ 218,944
Future income taxes, discounted at 10%	28,711	1,563
Pre-tax net present value, discounted at 10%	$ 286,553	$ 220,507

The following table reflects our estimated proved reserves, by category, as of December 31, 2019 (dollars in thousands):

	Crude Oil and Condensate (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV - 10
Proved developed producing	9,815	122,033	10,476	243,781	77 %	$ 261,922
Proved developed non-producing	4	658	8	734	— %	758
Proved undeveloped	9,266	8,609	1,280	71,874	23 %	23,873
Total	19,085	131,300	11,764	316,389	100 %	$ 286,553

Our estimated net proved reserves as of December 31, 2019, volumetrically, were approximately 42% natural gas, 36% oil and condensate and 22% natural gas liquids.

Proved Developed Reserves

Total proved developed reserves increased from 79.2 Bcfe at December 31, 2018 to 244.5 Bcfe at December 31, 2019, an increase primarily attributable to the 188.3 Bcfe increase related to the Will Energy and White Star acquisitions and to additions of 5.6 Bcfe primarily related to wells drilled and put on production in 2019 in our NE Bullseye area of West Texas. Partially offsetting the noted 2019 increases were downward performance revisions of 9.7 Bcfe, primarily in our Offshore properties and Bullseye properties in West Texas, and 2019 production of 17.9 Bcfe.

The following table presents the changes in our total proved developed reserves for the year ended December 31, 2019:

	Proved Developed Reserves (Mmcfe)
Proved developed reserves at December 31, 2018	79,234
Acquisitions [(1)]	188,349
Extensions, discoveries and other additions [(2)]	5,624
Production	(17,940)
Negative revisions related to performance [(3)]	(9,660)
Revisions of previous estimates	(1,385)
Divestitures	(449)
Conversions & other	742
Proved developed reserves at December 31, 2019	244,515

(1) Acquisitions are related to the Will Energy and White Star acquisitions. See Note 4 – “Acquisitions and Dispositions” for more information.

(2) Extensions, discoveries and additions are primarily related to our NE Bullseye properties in West Texas and new PUDs in our Other Onshore region.

(3) Revisions are primarily related to our Offshore properties and Bullseye properties in West Texas. The Offshore revisions of 8.1 Bcfe are due to re-assessing future operating costs, as well as a revision to the reservoir model which affected the associated recoverable condensate volumes. The West Texas revisions of 4.0 Bcfe are related to the performance of our Bullseye wells, which impacted the economic expectations for future locations in the current low-price environment.

Proved Undeveloped Reserves

Total proved undeveloped reserves (“PUDs”) increased from 52.7 Bcfe at December 31, 2018 to 71.9 Bcfe at December 31, 2019. As noted in the table below, this increase was primarily attributable to 65.9 Bcfe in new PUD locations in our NE Bullseye area in West Texas as a result of our 2019 drilling program and our Other Onshore region, and was partially offset by a downward revision of 41.0 Bcfe related to the reduction in PUDs in our Bullseye area in West Texas due to the impact of lower performance, and realized prices on the PUD economics in this area.

Future drilling plans and timelines are re-evaluated at the end of each calendar year based on updated reserve reports, current drilling cost estimates, production costs and product price forecasts. Our development plan prioritizes reserves based on the capital requirements and the expected incremental net present value to be added. Generally, our plan is to convert PUDs to developed reserves in an order that is based on their economic importance and impact on production and cash flow, but other factors may be considered such as technical merit, product type, location and available working interest partners. The PUD conversion rate in 2019 and 2018 was 6.3% and 9.1%, respectively, of the total net present value of the Company's total PUDs at the beginning of the applicable year.

The Company annually reviews any PUDs to ensure their development within five years from the year in which the PUDs were added to proved reserves. The Company's financial resources are expected to be sufficient to drill all of the remaining 71.9 Bcfe of proved undeveloped reserves within the upcoming five year period. Development costs relating to the 71.9 Bcfe at December 31, 2019 are projected to be approximately $208.9 million over the next five years.

The following table presents the changes in our total proved undeveloped reserves for the year ended December 31, 2019:

	Proved Undeveloped Reserves (Mmcfe)
Proved undeveloped reserves at December 31, 2018	52,677
Extensions, discoveries and other additions [(1)]	65,921
Acquisitions [(2)]	4,348
Negative revisions related to performance [(3)]	(39,463)
Revisions of previous estimates	(3,133)
Conversion to proved developed	(1,575)
Other [(4)]	(6,901)
Proved undeveloped reserves at December 31, 2019	71,874

(1) Extensions, discoveries and additions are primarily associated with wells drilled in 2019 on NE Bullseye properties in West Texas and new PUD locations in our Other Onshore region.

(2) Acquisitions are related to the Will Energy and White Star acquisitions. See Note 4 – "Acquisitions and Dispositions" for more information.

(3) Revisions are primarily related to the performance of our Bullseye properties in West Texas, which impacted the economic expectations and drilling plans for those locations in the current commodity price environment.

(4) Other includes the reduction in PUD locations in non-core areas that are no longer expected to be drilled within the five year period, per further reserve review, and the plugging and abandoning of properties.

Significant Properties

Summary proved reserve information for our properties as of December 31, 2019, by region, is provided below (excluding reserves attributable to our equity investment in Exaro) (dollars in thousands):

	Proved Reserves				
Regions	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (Mmcfe)	PV - 10 [(1)]
Offshore GOM	196	27,370	992	34,495	$ 43,861
Central Oklahoma	5,856	56,090	7,039	133,456	122,637
Western Anadarko	1,183	29,326	1,787	47,147	37,215
West Texas	5,412	4,920	988	43,316	48,880
Other Onshore	6,438	13,594	958	57,975	33,960
Total	19,085	131,300	11,764	316,389	$ 286,553

(1) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prices for natural gas liquids in the table represent average prices for natural gas liquids used in the proved reserve estimates, calculated in accordance with applicable SEC rules. All prices, using SEC rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

While we are reasonably certain of recovering our calculated reserves, the process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our third party engineers must project production rates, estimate timing and amount of development expenditures, analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of all of this data may vary. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

Reserves Attributable to our Equity Investment in Exaro

Estimates of proved reserves and future net revenue as of December 31, 2019 and 2018 for Exaro, which we account for using the equity method, were prepared by Von Gonten in accordance with the definitions and regulations of the SEC. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE.

The specific technical individual at Von Gonten responsible for overseeing the preparation of our reserve estimates as of December 31, 2019 and December 31, 2018 has over 18 years of practical experience in the estimation and evaluation of reserves, is a registered professional engineer in the state of Texas, holds a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University and is a member in good standing of the SPE.

The following table reflects the estimated proved reserves attributable to our equity investment in Exaro:

	December 31, 2019	December 31, 2018
Crude Oil (MBbl)		
Developed	225	272
Undeveloped	—	—
Total	225	272
Natural Gas (MMcf)		
Developed	21,607	24,965
Undeveloped	—	—
Total	21,607	24,965
Total MMcfe		
Developed	22,955	26,595
Undeveloped	—	—
Total [3]	22,955	26,595
Proved developed reserves percentage	100 %	100 %
Standardized measure *(in thousands)* [1]	$ 15,308	$ 21,001
Prices realized in estimates [2]		
Crude oil ($/Bbl)	$ 55.65	$ 63.57
Natural gas ($/MMBtu)	$ 2.60	$ 2.99

(1) The Company's share of the standardized measure of discounted future net cash flows attributable to our equity investment in Exaro does not include the effect of income taxes because Exaro is treated as a partnership for tax purposes. Exaro allocates any income or expense for tax purposes to its partners.

(2) Under SEC rules, prices used in determining our proved reserves are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). All prices are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

(3) During the year ended December 31, 2019, the decrease in Exaro’s proved reserves attributable to our investment in Exaro was approximately 3.6 Bcfe.

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of December 31, 2018 and 2017 are disclosed in “Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Disclosures (Unaudited)”. Reserves as of December 31, 2018 and 2017 were based on reserve reports generated by NSAI and Cobb, while the reserves associated with our 37% equity investment in Exaro were prepared by Von Gonten.

Item 3. ***Legal Proceedings***

From time to time, the Company is involved in legal proceedings relating to claims associated with its properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

On November 16, 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decades-old, poorly documented transactions. Based on prior summary judgments, the trial court entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company appealed the trial court's decision to the applicable state Court of Appeals, and in the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court's summary decision. In the first quarter of 2018, the Company filed a motion for rehearing with the Court of Appeals, which was denied, as expected. The Company filed a petition requesting a review by the Texas Supreme Court, as the Company believes the trial and appellate courts erred in the interpretation of the law. In early October 2019, the Texas Supreme Court notified the Company that it would not hear this case. The Company engaged additional legal representation to assist in the preparation of an amended petition requesting that the Texas Supreme Court reconsider its initial decision to not review the case. That amended petition was filed, and in mid-March 2020, the Texas Supreme Court decided they would not re-hear the case. Consequently, during the three months ended December 31, 2019, the Company recorded a $6.3 million liability for the judgment, interest and fees, with $3.5 million of such liability related to suspended funds currently reflected in "Accounts payable and accrued liabilities" on the Company's consolidated balance sheet.

On January 14, 2016, the Company was named as the defendant in a lawsuit filed in the District Court for Harris County in Texas by a third-party operator. The Company participated in the drilling of a well in 2012, which experienced serious difficulties during the initial drilling, which eventually led to the plugging and abandoning of the wellbore prior to reaching the target depth. In dispute is whether the Company is responsible for the additional costs related to the drilling difficulties and plugging and abandonment. In September 2019, the case went to trial, and, in October 2019, the court ruled in favor of the plaintiff. Prior to the judgment, the Company had approximately $1.1 million in accounts payable related to the disputed costs associated with this case. As a result of the judgment, during the three months ended September 30, 2019, the Company recorded an additional $2.1 million liability for the final judgment plus fees and interest. The Company has since prepared and filed an appeal with the appellate court for a review of the initial trial court decision and is awaiting the court's response.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

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.***

Our common stock is listed on the NYSE American under the symbol "MCF".

As of March 23, 2020, there were approximately 228 registered shareholders of our common stock and 8 registered holders of our Series C preferred stock.

Holders of common stock are entitled to such dividends as may be declared by the board of directors out of funds legally available. Therefore, any decision to pay future dividends on our common stock will be at the discretion of our board of directors and will depend upon our financial condition, results of operations, capital requirements and other factors our board of directors may deem relevant. We do not anticipate paying any cash dividends on our common stock in the foreseeable future, as we currently intend to retain all future earnings to fund the development and growth of our business. Our Credit Agreement with JPMorgan Chase Bank, N.A. and other lenders currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases are subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. The repurchase program does not have an expiration date. No shares were purchased for the years ended December 31, 2019 and 2018. As of December 31, 2019, the Company has $31.8 million available under its share repurchase program, however, those repurchases could be limited under restrictions in the Company's Credit Agreement.

In addition, the Company withheld the following shares, outside of the repurchase program, on a cashless basis from employees as their payment of withholding taxes due on vesting shares of restricted stock previously issued under our stock-based compensation plans:

Period	Total Number of Shares Withheld	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet be Purchased Under Program
October 2019	7,131	$ 2.49	—	—
November 2019	199	$ 2.95	—	—
December 2019	—	$ —	—	—
	7,330	$ 2.50	—	$ 31.8 million

Item 6. ***Selected Financial Data***

Sale of Unregistered Securities

For a description of the Company's private placements of Series B preferred stock in November 2019 and common stock and Series C preferred stock in December 2019, please see "Overview" in Item 1. Business.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the financial statements and the related notes and other information included elsewhere in this report.

Overview

We are a Houston, Texas based independent oil and natural gas company, with regional offices in Oklahoma City and Stillwater, Oklahoma. Our business is to maximize production and cash flow from our offshore properties in the shallow waters of the Gulf of Mexico ("GOM") and onshore Texas, Oklahoma, Louisiana and Wyoming properties and use that cash flow to explore, develop, exploit and acquire oil and natural gas properties across the United States. We were originally formed in 1999 as a Nevada corporation and changed our state of incorporation to the State of Delaware in 2000. On June 14, 2019, following approval by our stockholders at the 2019 annual meeting of stockholders, we changed our state of incorporation from the State of Delaware to the State of Texas and increased our number of authorized shares of common stock from 50 million to 100 million. On December 12, 2019, following approval by our stockholders by executed and delivered written consent, we increased our number of authorized shares of common stock from 100 million to 200 million.

In December 2019, we entered into a Joint Development Agreement with Juneau Oil & Gas, LLC ("Juneau"), which provides us the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. See Note 4 – "Acquisitions and Dispositions" for more information.

In September 2019, we entered into unrelated purchase agreements with Will Energy Corporation ("Will Energy") and White Star Petroleum, LLC and certain of its affiliates (collectively, "White Star") to purchase certain producing assets and undeveloped acreage, primarily in Oklahoma. These transactions closed during the three months ended December 31, 2019. See Note 4 – "Acquisitions and Dispositions" for more information.

Also in September 2019, we entered into a new revolving credit agreement with JPMorgan Chase Bank, N.A. and other lenders (the "Credit Agreement"). In connection with the entry into the Credit Agreement, we repaid all obligations outstanding on, and terminated, the previous credit agreement with Royal Bank of Canada. The Credit Agreement was amended on November 1, 2019, in conjunction with the closing of the Will Energy and White Star acquisitions, to add two additional lenders and increase the borrowing base thereunder from $65 million to $145 million. See Note 13 – "Long-Term Debt" for more information.

From our initial entry into the Southern Delaware Basin in 2016 and through early 2019, we focused on the development of our initial 6,500 net acre position in Pecos County, Texas ("Bullseye"), and in December 2018, we purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of our Bullseye acreage ("NE Bullseye") for approximately $7.5 million. We paid $3.2 million cash in December 2018, with the remaining cash balance paid in installments in March and October of 2019. Our 2019 drilling program included the completion of one well previously drilled in the Bullseye area, the drilling and completion of a second Bullseye well, and the drilling and completion of three wells in the NE Bullseye area. As of December 31, 2019, we were producing from seventeen wells over our approximate 18,600 gross operated (8,000 total net) acre position in West Texas, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. In December 2019, we began completion operations on our fourth NE Bullseye well, which began producing in January 2020. Also in December, we completed and brought on production a Garfield County, Oklahoma well in the Company's Central Oklahoma region, which it acquired in connection with the White Star acquisition. See Note 4 – "Acquisitions and Dispositions" for more information.

In response to low commodity prices and a related window of opportunity to acquire producing properties on very attractive terms, we finished our 2019 drilling program that was designed to only preserve core areas of our West Texas play, and thereafter focused on identifying, evaluating and acquiring producing reserves. As a result, we were successful in closing the Will Energy and White Star acquisitions in the fourth quarter of 2019. For 2020, we believe that a continuing low price environment and a shortage of capital available to the industry may present more opportunities to acquire additional producing properties that could provide strong production, cash flow and future development potential at attractive rates of return. We plan to be active in pursuing such acquisition opportunities and then allowing our technical teams to leverage our experience and expertise to work on increasing returns through production enhancement, cost reduction and future development of the unproved drilling locations that comes with the production acquired. We can provide no assurances that we will acquire any producing property opportunities on attractive terms, or at all, or that we will realize the expected benefits of any acquisition. We also currently plan to limit our 2020 drilling program to only address leasehold commitments and preserve core acreage in our existing areas, while complementing that strategy with one to two relatively low cost, high-potential offshore exploratory wells on prospects recently acquired from Juneau. See Note 4 – “Acquisitions and Dispositions” for more information. We will continue to make balance sheet strength a priority in 2020 as we utilize excess cash flow to reduce debt and increase our capacity to quickly react to acquisition opportunities.

We are also currently undertaking an extensive review of all of our producing areas in light of the commodity price environment, and where determined justified and operationally feasible, we plan to potentially shut in or curtail unhedged production. Because of our low debt profile and borrowing cost of capital, we believe we may be able to temporarily shut in or curtail higher cost production when there is a decline in the commodity markets. We are also currently re-evaluating the economic justification for proceeding with the production-enhancing workover program originally scheduled for the first half of 2020. The limited onshore development drilling we planned for 2020 is also being re-evaluated.

Our production for the year ended December 31, 2019 was approximately 17.9 Bcfe (or 49.2 Mmcfe/d) and was 41% offshore and 59% onshore. Our production for the three months ended December 31, 2019 was approximately 8.7 Bcfe (or 94.2 Mmcfe/d) and was 20% offshore and 80% onshore. The production rates include November and December 2019 production from our acquired properties in the Western Anadarko, Central Oklahoma and Other Onshore regions. See Note 4 – “Acquisitions and Dispositions” for more information. As of December 31, 2019, our proved reserves were approximately 89% of total volumes onshore, approximately 42% of total volumes gas and were 77% proved developed (volumetrically).

Revenues and Profitability

Our revenues, profitability and future growth depend substantially on our ability to find, develop and acquire natural gas and oil reserves that are economically recoverable, as well as prevailing prices for natural gas and oil.

Reserve Replacement

Generally, producing properties offshore in the Gulf of Mexico have high initial production rates, followed by steep declines. Likewise, initial production rates on new wells in the onshore resource plays start out at a relatively high rate with a decline curve which results in 60% to 70% of the ultimate recovery of present value occurring in the first eighteen months of the well’s life. We must locate and develop, or acquire, new natural gas and oil reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and/or acquire natural gas and oil reserves. A prolonged period of depressed commodity prices could have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes in our development plans.

Use of Estimates

The preparation of our financial statements requires the use of estimates and assumptions that affect the reported amounts of 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 periods. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include estimates of remaining proved natural gas and oil reserves, the timing and costs of our future drilling, development and abandonment activities, and income taxes.

See “Item 1A. Risk Factors” for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations.

Results of Operations

The table below sets forth our average net daily production data in Mmcfe/d from our fields for each of the periods indicated:

	Three Months Ended							
	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019
Offshore GOM [1] [2]	32.0	23.7	27.2	25.3	23.5	19.1	20.0	18.9
Central Oklahoma [3]	—	—	—	—	—	—	—	48.5
Western Anadarko [3]	—	—	—	—	—	—	—	10.2
West Texas [4]	4.5	6.7	6.4	7.5	5.9	5.9	5.6	8.3
Other Onshore [3] [5]	13.5	12.0	10.0	7.0	6.5	7.3	8.1	8.3
	50.0	42.4	43.6	39.8	35.9	32.3	33.7	94.2

(1) Includes a decreased production rate of 4.2 Mmcfe/d due to downtime related to compressor installation and maintenance during the three months ended June 30, 2018 and a decreased production rate of 1.9 Mmcfe/d due to downtime for pipeline and compressor repair and maintenance during the three months ended June 30, 2019. Our GOM production was not materially affected by Hurricane Michael which passed through the northeastern GOM in October 2018.

(2) Our Vermilion 170 offshore well was sold effective December 1, 2018. It produced at an average daily rate of 2.2 Mmcfe/d during 2018.

(3) Includes November and December production from properties acquired as part of the White Star and Will Energy acquisitions. See Note 4 – "Acquisitions and Dispositions" for more information.

(4) Increase in production during the three months ended December 31, 2019 due to bringing three wells online in our NE Bullseye area.

(5) Includes production from various non-core properties in our South, Southeast and East Texas, Louisiana and Wyoming areas. The declines show can be attributed to normal field decline and sales of certain properties over the time frame shown. Increase in production during the three months ended December 31, 2019 is primarily due to certain Louisiana properties acquired as part of the Will Energy acquisition. See Note 4 – "Acquisitions and Dispositions" for more information.

Non-Core Asset Sales

During the years ended December 31, 2019 and 2018, we completed certain non-core asset sales to enhance our liquidity, eliminate marginal assets and reduce future asset retirement obligations and administrative costs, allowing us to focus our operational efforts on our West Texas and recently acquired Oklahoma properties. These asset sales provide some immediate liquidity and improve our balance sheet by removing future asset retirement obligations.

In June 2019 and July 2019, we sold certain non-core operated assets located in Lavaca and Wharton counties, Texas, and Frio and Zavala counties, Texas, respectively, in exchange for the buyers' assumption of the future plugging and abandonment liabilities associated with the sold properties.

During the year ended 2018, we sold certain Eagle Ford Shale assets in Karnes County, Texas for $21.0 million; Gulf Coast conventional assets in Southeast Texas for $6.0 million, and Gulf Coast conventional and unconventional assets in South Texas for $0.9 million. In December 2018, we also sold our offshore Vermilion 170 property in exchange for a retained overriding royalty interest ("ORRI") in the well, the buyer's assumption of the plugging and abandonment obligation and an ORRI in any future wells drilled by the buyer on two nearby prospects that would produce through this platform.

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

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the years ended December 31, 2019 and 2018. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six Mcf of natural gas. Reported operating expenses include production taxes, such as ad valorem and severance.

	Year Ended December 31,		
	2019	2018	%
Revenues (thousands):			
Oil and condensate sales	$ 44,705	$ 34,413	30 %
Natural gas sales	22,380	29,824	(25)%
NGL sales	9,427	12,850	(27)%
Total revenues	$ 76,512	$ 77,087	(1)%
Production:			
Oil and condensate (thousand barrels)			
Offshore GOM	43	73	(41)%
Central Oklahoma	196	—	100 %
Western Anadarko	42	—	100 %
West Texas	275	275	— %
Other Onshore	235	221	6 %
Total oil and condensate	791	569	39 %
Natural gas (million cubic feet)			
Offshore GOM	5,908	7,704	(23)%
Central Oklahoma	1,839	—	100 %
Western Anadarko	552	—	100 %
West Texas	320	285	12 %
Other Onshore	904	1,790	(49)%
Total natural gas	9,523	9,779	(3)%
Natural gas liquids (thousand barrels)			
Offshore GOM	210	287	(27)%
Central Oklahoma	242	—	100 %
Western Anadarko	23	—	100 %
West Texas	64	59	8 %
Other Onshore	73	128	(43)%
Total natural gas liquids	612	474	29 %
Total (million cubic feet equivalent)			
Offshore GOM	7,424	9,865	(25)%
Central Oklahoma	4,466	—	100 %
Western Anadarko	941	—	100 %
West Texas	2,350	2,294	2 %
Other Onshore	2,759	3,880	(29)%
Total production	17,940	16,039	12 %
Daily Production:			
Oil and condensate (thousand barrels per day)			
Offshore GOM	0.1	0.2	(41)%
Central Oklahoma	0.5	—	100 %
Western Anadarko	0.1	—	100 %
West Texas	0.8	0.8	— %
Other Onshore	0.7	0.6	6 %
Total oil and condensate	2.2	1.6	39 %

	Year Ended December 31, 2019	2018	%
Natural gas (million cubic feet per day)			
Offshore GOM	16.2	21.1	(23)%
Central Oklahoma	5.0	—	100 %
Western Anadarko	1.5	—	100 %
West Texas	0.9	0.8	12 %
Other Onshore	2.5	4.9	(49)%
Total natural gas	26.1	26.8	(3)%
Natural gas liquids (thousand barrels per day)			
Offshore GOM	0.6	0.8	(27)%
Central Oklahoma	0.7	—	100 %
Western Anadarko	0.1	—	100 %
West Texas	0.2	0.2	8 %
Other Onshore	0.1	0.3	(43)%
Total natural gas liquids	1.7	1.3	29 %
Total (million cubic feet equivalent per day)			
Offshore GOM	20.3	27.0	(25)%
Central Oklahoma	12.2	—	100 %
Western Anadarko	2.6	—	100 %
West Texas	6.4	6.3	2 %
Other Onshore	7.7	10.6	(29)%
Total production	49.2	43.9	12 %
Average Sales Price:			
Oil and condensate (per barrel)	$ 56.55	$ 60.43	(6)%
Natural gas (per thousand cubic feet)	$ 2.35	$ 3.05	(23)%
Natural gas liquids (per barrel)	$ 15.39	$ 27.04	(43)%
Total (per thousand cubic feet equivalent)	$ 4.26	$ 4.80	(11)%
Expenses (thousands):			
Operating expenses	$ 33,205	$ 25,552	30 %
Exploration expenses	$ 1,003	$ 1,637	(39)%
Depreciation, depletion and amortization	$ 39,807	$ 41,657	(4)%
Impairment and abandonment of oil and gas properties	$ 128,290	$ 103,732	24 %
General and administrative expenses	$ 24,938	$ 24,157	3 %
Gain (loss) from investment in affiliates (net of taxes)	$ 742	$ (12,721)	(106)%
Other (Income) Expense	$ (9,587)	$ 10,921	(188)%
Selected data per Mcfe:			
Operating expenses	$ 1.85	$ 1.59	16 %
General and administrative expenses	$ 1.39	$ 1.51	(8)%
Depreciation, depletion and amortization	$ 2.22	$ 2.60	(15)%

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, oil and NGL production. Our revenues may vary significantly from year to year depending on production volumes and changes in commodity prices, each of which may fluctuate widely. Our production volumes are subject to significant variation as a result of new operations, weather events, transportation and processing constraints and mechanical issues. In addition, our production from individual wells naturally declines over time as we produce our reserves.

We reported revenues of approximately $76.5 million for the year ended December 31, 2019, compared to revenues of approximately $77.1 million for the year ended December 31, 2018. The incremental revenue added in mid-fourth quarter 2019 from the White Star and Will Energy acquisitions, and the new production added during the latter half of the year from the commencement of production from wells completed in West Texas, were substantially offset for the year in total, by the year over year decline in legacy production and by lower commodity prices. Fourth quarter 2019 revenues were $37.2 million, compared to $18.7 million in revenues for the 2018 comparative quarter, with $22.9 million of that increase attributable to the addition of November and December 2019 revenues from the Will Energy and White Star acquisitions.

Total production for the year ended December 31, 2019 was approximately 17.9 Bcfe, or 49.2 Mmcfe/d, compared to approximately 16.0 Bcfe, or 43.9 Mmcfe/d, in the prior year. For the fourth quarter of 2019, production averaged 94.2 Mmcfe/d compared to the 2018 quarter average of 39.8 Mmcfe/d, an increase attributable primarily to the White Star and Will Energy acquisitions. The properties acquired from White Star and Will Energy produced at an average rate of approximately 90.6 Mmcfe/d for November and December 2019, which contributed 60.0 Mmcfe/d and 15.1 Mmcfe/d to the fourth quarter and year to date 2019 averages, respectively. The daily production from our offshore properties declined 6.7 Mmcfe/d for the year ended December 31, 2019, primarily due to the year over year natural decline in production and various occurrences of downtime for compressor and pipeline issues.

Net natural gas production for the year ended December 31, 2019 was approximately 26.1 Mmcf/d, compared with approximately 26.8 Mmcf/d for the year ended December 31, 2018. For the fourth quarter of 2019, production averaged 45.0 Mmcf/d compared to the 2018 quarter average of 23.1 Mmcf/d. The properties acquired from White Star and Will Energy produced at an average rate of approximately 40.4 Mmcf/d for November and December 2019, which contributed 26.8 Mmcf/d and 6.7 Mmcf/d to the overall fourth quarter and year to date 2019 averages, respectively.

Net oil production increased from approximately 1,600 barrels per day in 2018 to 2,200 barrels per day in 2019, while NGL production increased from approximately 1,300 barrels per day in 2018 to 1,700 barrels per day in 2019. For the fourth quarter of 2019, net oil production averaged 4,400 barrels per day compared to the 2018 quarter average of 1,500 barrels per day, and the net NGL production averaged 3,800 barrels per day compared to the 2018 quarter average of 1,300 barrels per day. The net oil production from the White Star and Will Energy properties was approximately 4,000 barrels per day for November and December 2019, which contributed 2,700 barrels per day and 700 barrels per day to the fourth quarter and year to date 2019 averages, respectively. The net NGL production from the White Star and Will Energy properties was approximately 4,300 barrels per day for November and December 2019, which contributed 2,900 barrels per day and 700 barrels per day to the overall fourth quarter and year to date 2019 averages, respectively.

Average Sales Prices

The average equivalent sales price realized for the years ended December 31, 2019 and 2018 was $4.26 per Mcfe and $4.80 per Mcfe, respectively. This decline was attributable to the decrease in realized prices of all commodities. The realized price of gas was $2.35 per Mcf in 2019 compared to $3.05 per Mcf for 2018. The realized price of oil was $56.55 in 2019 compared to $60.43 in 2018, and the realized price of NGLs was $15.39 in 2019 compared to $27.04 in 2018.

Operating Expenses (including production taxes)

Total operating expenses for the year ended December 31, 2019 were approximately $33.2 million, or $1.85 per Mcfe, compared to approximately $25.6 million, or $1.59 per Mcfe, for the year ended December 31, 2018. The table below provides additional detail of total operating expenses for those periods.

	Twelve Months Ended December 31,			
	2019		2018	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 20,644	$ 1.15	$ 17,471	$ 1.09
Production & ad valorem taxes	3,607	0.20	3,070	0.19
Transportation & processing costs	6,085	0.34	2,791	0.17
Workover costs	2,869	0.16	2,220	0.14
Total operating expenses	$ 33,205	$ 1.85	$ 25,552	$ 1.59

Lease operating expenses increased $3.2 million for the year ended December 31, 2019, compared to the prior year, primarily due to additional expense of $7.5 million ($1.36 per associated Mcfe produced) in November and December 2019 related to the Will Energy and White Star acquisitions, partially offset by a $4.9 million decrease related primarily to non-core property sales.

Transportation and processing costs increased $3.3 million for the year ended December 31, 2019, compared to the prior year due to additional transportation expense of $3.7 million ($0.68 per associated Mcfe produced) in November and December 2019 related to the Will Energy and White Star acquisitions, partially offset by lower minimum throughput commitment fees in 2019. See Note 14 – "Commitments and Contingencies" for further information.

Exploration Expenses

We reported approximately $1.0 million and $1.6 million of exploration expenses for the years ended December 31, 2019 and 2018, respectively, which were primarily related to geological and geophysical software, seismic data licensing fees and mapping services.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization expense for the year ended December 31, 2019 was approximately $39.8 million, or $2.22 per Mcfe, compared to approximately $41.7 million, or $2.60 per Mcfe, for the year ended December 31, 2018. The Will Energy and White Star acquisitions contributed an additional $5.4 million ($0.98 per associated Mcfe produced) in depreciation, depletion and amortization expense.

Impairment and Abandonment of Oil and Gas Properties

Impairment and abandonment expenses for the year ended December 31, 2019, included non-cash proved property impairment expense of $117.8 million due to reserve revisions which resulted from the negative impact of performance and price related revisions to the present value of our year-end proved reserves, and the relationship of that value to the historical carrying cost of our assets on the balance sheet. Included in the impairment charge was $34.5 million related to our proved offshore Gulf of Mexico properties, primarily a result of performance revisions associated with the re-evaluation of the projected field costs and recoverable condensate volumes. In addition, we recognized onshore proved property impairment expense of $83.3 million, including $73.7 million in the Bullseye area in our West Texas region and $9.6 million in our Other Onshore region. The onshore impairment was primarily due to performance revisions and changes in realizable prices on the producing properties, which led to the re-evaluation of the economics and future drilling plans for the proved undeveloped locations in such areas in the current commodity price environment, which then resulted in the elimination of certain proved undeveloped locations due to the SEC's five year development rule for such locations.

During the year ended December 31, 2019, we recognized non-cash unproved impairment expense of approximately $9.2 million related primarily to lease expirations, and near-term expirations, in the Bullseye portion of our West Texas area.

Impairment and abandonment expenses for the year ended December 31, 2018 included proved property impairment of approximately $101.9 million. Included in the impairment charges incurred in 2018 was a $61.7 million impairment of the carrying costs of our offshore Gulf of Mexico proved properties primarily due to revised proved reserve estimates made during the quarter ended September 30, 2018. This impairment was primarily a result of new bottom hole pressure data gathered during the planned installation of a second stage of compression in our Eugene Island 11 field. In 2018, we also recognized onshore proved property impairment expense of $40.2 million, of which $24.9 million was related to the impairment of certain of our non-core properties in South and Southeast Texas that were reduced to their fair value as a result of planned sales during the quarters ended September 30, 2018 and December 31, 2018, and $15.3 million of impairment was due to price related reserve revisions primarily on our Wyoming and certain South Texas assets. See Note 4 – "Acquisitions and Dispositions" for further information regarding the property dispositions.

During the year ended December 31, 2018, we recognized non-cash unproved impairment expense of approximately $1.3 million related to properties due to expiring leases.

General and Administrative Expenses

Total general and administrative expenses for the years ended December 31, 2019 and 2018 was approximately $24.9 million and $24.2 million, respectively.

The table below provides additional detail of general and administrative expenses for each of the twelve month periods:

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Wages, bonuses and employee benefits [1]	$ 3,955	9,347
Non-cash stock-based compensation [1]	2,352	4,766
Professional fees [2]	5,080	4,642
Professional fees - special [3]	4,177	-
Legal judgments [4]	4,973	-
Other [5]	4,401	5,402
Total general and administrative expenses	$ 24,938	$ 24,157

(1) Lower expense primarily due to lower head count during the first ten months of 2019. 2018 expense includes a $1.8 million severance payment made upon the resignation of our former President and CEO.
(2) Primarily includes fees related to recurring legal, technical consultants, and accounting and auditing.
(3) Non-recurring fees incurred in conjunction with our pursuit of strategic initiatives.
(4) Includes accruals for legal judgments. See Note 14 – “Commitments and Contingencies” for more information.
(5) Includes fees related to insurance, office costs and other company expenses.

Gain (loss) from Affiliates

For the year ended December 31, 2019 and 2018, we recorded a gain from affiliates of approximately $1.0 million, net of zero expense, and a loss of approximately $12.6 million, net of zero tax expense, respectively, related to our equity investment in Exaro.

Other Income

Other income for the year ended December 31, 2019 was approximately $9.6 million, which primarily consists of $8.6 million in interest expense, of which $4.0 million related to non-refundable financing and commitment fees, and $3.4 million in net losses on derivatives, partially offset by $0.5 million gain on the sale of assets and a $0.6 million pipeline imbalance settlement related to prior years’ activity.

Other income for the year ended December 31, 2018 was approximately $10.9 million, which consists primarily of a $13.2 million gain on the sale of assets, a $1.9 million net gain on derivatives and a $0.9 million reimbursement claim under our property and casualty insurance policy. Other income was partially offset by interest expense of $5.5 million.

Capital Resources and Liquidity

Our primary cash requirements are for capital expenditures, working capital, operating expenses, acquisitions and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations, net of the realized effect of our hedging agreements, and amounts available to be drawn under our Credit Agreement.

During the year ended December 31, 2019, we incurred expenditures of $43.4 million on capital projects, including $35.4 million for our drilling program in the Southern Delaware Basin and $2.7 million in leasehold acquisition costs in the Southern Delaware Basin. We also incurred $2.4 million for the drilling and completion of three non-operated wells targeting the Georgetown formation in our Other Onshore region. The remaining incurred expenditures are primarily related to capitalized workovers.

In September 2019, we entered into a purchase agreement with Will Energy and a purchase agreement with White Star to purchase certain producing assets and undeveloped acreage. See Note 4 – “Acquisitions and Dispositions” for more information. The closing of the Will Energy acquisition occurred on October 25, 2019, for aggregate consideration of $23 million. Following adjustments for recent sales of non-core, non-operated Louisiana properties by Will Energy, the results of operations for the period between the effective and closing dates, and other estimated, customary closing adjustments, the net consideration paid consisted of $14.75 million in cash and 3.5 million shares of our common stock. Closing of the White Star acquisition occurred on November 1, 2019, for a total aggregate consideration of $132.5 million. Following adjustments for the results of operations for the period between the effective and closing dates, and other customary closing adjustments, the net consideration paid was $95.9 million in cash.

The Will Energy acquisition was partially funded with proceeds from a public offering of our common stock and a private placement of Series A contingent convertible preferred stock, both completed on September 12, 2019, from which we received total net proceeds of approximately $53.7 million. The White Star acquisition was partially funded with proceeds from a private placement of Series B contingent convertible preferred stock, completed on November 1, 2019, from which we received total net proceeds of approximately $21.0 million. See Note 1 – "Organization and Business" for more information regarding the public offering and private purchase agreements. The remaining cash consideration was funded through borrowings under our Credit Agreement.

In December 2019, we entered into a Joint Development Agreement with Juneau for aggregate consideration of $6.0 million, consisting of $1.69 million in cash and 1,725,000 shares of common stock of the Company. The agreement provides us the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. See Note 4 – "Acquisitions and Dispositions" for more information.

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the periods indicated, in thousands.

	Year ended December 31,	
	2019	2018
Net cash provided by operating activities	$ 21,710	$ 23,477
Net cash used in investing activities	$ (154,855)	$ (30,687)
Net cash provided by financing activities	$ 134,769	$ 7,210
Cash and cash equivalents at the end of the period	$ 1,624	$ —

Cash flow from operating activities, including changes in working capital, provided approximately $21.7 million in cash for the year ended December 31, 2019 compared to $23.5 million for the year ended December 31, 2018. Included in 2019 activity is approximately $4.2 million related to strategic initiatives and non-recurring expenses, of which approximately $1.9 million is related to the White Star acquisition. Cash flow from operating activities, excluding changes in working capital, provided approximately $14.6 million in cash for the year ended December 31, 2019 compared to $22.1 million for the year ended December 31, 2018. Cash provided due to changes in working capital were approximately $7.1 million during 2019, compared to $1.4 million during 2018 and represent normal receivable and payable activity during the period.

Net cash flows used in investing activities were $154.9 million for the year ended December 31, 2019, which included $112.1 million in cash for the Will Energy and White Star acquisitions and the Joint Development Agreement with Juneau. Additionally, we expended $42.8 million in cash capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin and non-operated wells in the Georgetown formation.

Net cash flows used in investing activities were $30.7 million for the year ended December 31, 2018. We expended $59.0 million in cash capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases, partially offset by $27.8 million in cash proceeds from the sale of our non-core properties.

Cash flows provided by financing activities were approximately $134.8 million for the year ended December 31, 2019 compared to $7.2 million provided financing activities in 2018. Included in 2019 activity was $125.7 million in total net proceeds from our equity offerings, $60.0 million in repaid borrowings for the termination of our previous credit facility and $72.8 million in net borrowings under our new Credit Agreement. Included in 2018 activity was $33.0 million in proceeds from our equity offering and approximately $25.4 million in net repayments of outstandings under our previous credit facility with the Royal Bank of Canada.

Credit Agreement

On September 17, 2019, we entered into a new revolving credit agreement with JPMorgan Chase Bank, N.A., which established a borrowing base of $65 million. The Credit Agreement was amended on November 1, 2019, in conjunction with the closing of the Will Energy and White Star acquisitions, to add two additional lenders and increase the borrowing base thereunder to $145 million, which is the current borrowing base. The borrowing base is subject to semi-annual redeterminations and may also be adjusted by certain events, including the incurrence of any senior unsecured debt, material asset dispositions or liquidation of hedges in excess of certain thresholds. Beginning in 2020, the semi-annual redeterminations will occur on May 1st and November 1st of each year. The Credit Agreement matures on September 17, 2024. As of December 31, 2019, the borrowing availability under the Credit Agreement was $70.3 million.

The Credit Agreement contains customary and typical restrictive covenants. Commencing in the quarter ending December 31, 2019, the Credit Agreement requires a Current Ratio of greater than or equal to 1.00 and a Leverage Ratio of less than or equal to 3.50, both as defined in the Credit Agreement. As of December 31, 2019, we were in compliance with all financial covenants under the Credit Agreement.

Future Capital Requirements

Our future oil, natural gas and natural gas liquids reserves and production, and therefore our 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 anticipate that acquisitions, including those of undeveloped leasehold interests, will continue to play a role in our business strategy as those opportunities arise from time to time; however, there can be no assurance that we will be successful in consummating any acquisitions, or that any such acquisition entered into will be successful. These potential acquisitions are not part of our current capital budget and would require additional capital. Natural gas and oil prices continue to be volatile, and our financial resources may be insufficient to fund any of these opportunities. While there are currently no unannounced agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly and could occur at any time.

We believe that our internally generated cash flow and proceeds from the sale of non-core assets, combined with availability under our Credit Agreement will be sufficient to meet the liquidity requirements necessary to fund our daily operations and planned capital development and to meet our debt service requirements for the next twelve months. Our ability to execute on our growth strategy will be determined, in large part, by our cash flow and the availability of debt and equity capital at that time. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors.

Our 2020 capital budget will be focused primarily on: (i) preserving our financial position, including limiting capital expenditures to internally generated cash flow and proceeds from the sale of non-core assets; (ii) focusing drilling expenditures on strategic projects that provide good investment returns in the current price environment; and (iii) identifying opportunities for cost efficiencies in all areas of our operations. Our 2020 capital expenditure budget is currently estimated at approximately $13.1 million and is expected to include the following:

- Offshore GOM: the Iron Flea prospect in the Grand Isle Block 45/46 area in the shallow waters off of the Louisiana coast will require $6.3 million to drill and $0.8 million to abandon in the case of dry hole. We expect that capital expenditures will exceed this amount if the prospect is a success due to evaluation and completions costs and the possibility of a second well and /or facilities.
- West Texas: $3.3 million to drill and complete one salt water disposal well and $0.4 million for infrastructure costs in our NE Bullseye area.
- Central Oklahoma: $2.3 million to complete three previously drilled wells, which we acquired from White Star.

Our current capital budget for 2020 should allow us to meet our contractual requirements and remain in position to preserve our term acreage where appropriate during this challenging period for our industry. We will continuously monitor the commodity price environment and economic conditions, and if warranted, make adjustments to our investment strategy as the year progresses.

Inflation and Changes in Prices

While the general level of inflation affects certain costs associated with the energy industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have, a material effect on our operations; however, we cannot predict these fluctuations.

Income Taxes

During the year ended December 31, 2019, we paid approximately $0.7 million in state income taxes and no federal income taxes. During the year ended December 31, 2018, we paid approximately $0.1 million in state income taxes and no federal income taxes.

Application of Critical Accounting Policies and Management's Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company's significant accounting policies are described in Note 2 of Notes to Consolidated Financial Statements included as part of this Form 10-K. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to natural gas and oil reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company's consolidated financial statements:

Oil and Gas Properties - Successful Efforts

Our application of the successful efforts method of accounting for our natural gas and oil exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Reserve Estimates

While we are reasonably certain of recovering our reported reserves, the Company's estimates of natural gas and oil reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating producible underground accumulations of natural gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable natural gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future natural gas and oil prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future development costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected natural gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's natural gas and oil properties and/or the rate of depletion of such natural gas and oil properties.

Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material. Holding all other factors constant, a reduction in the Company's proved reserve estimate at December 31, 2019 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $0.8 million, $1.6 million and $2.6 million, respectively.

Impairment of Natural Gas and Oil Properties

The Company reviews its proved natural gas and oil properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. An impairment loss associated with an asset group is the amount by which the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. An asset's fair value is preferably indicated by a quoted market price in the asset's principal market. Unlike many businesses where independent appraisals can be obtained for items such as equipment, oil and gas proved reserves are unique assets. Most oil and gas valuations are based on a combination of the income approach and market approach methodologies. We utilize the income approach also known as the discounted cash flow ("DCF") approach. Under the DCF method in determining fair value, there are specific guidelines and ranges within the evaluation that we can consider and estimate.

The Company compares expected undiscounted future net cash flows from each field to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows, based on the Company's estimate of future natural gas and oil prices and operating costs and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates and anticipated capital expenditures. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Drilling activities in an area by other companies may also effectively impair leasehold positions. Given the complexities associated with natural gas and oil reserve estimates and the history of price volatility in the natural gas and oil markets, events may arise that will require the Company to record an impairment of its natural gas and oil properties and there can be no assurance that such impairments will not be required in the future nor that they will not be material.

Derivative Instruments

The Company elected to not designate any of its derivative positions for hedge accounting. At the end of each reporting period, we record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives, along with the realized gain or loss for settled derivatives, is reported in "Other Income (Expense)" as "Gain (loss) on derivatives, net".

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. We are subject to taxation in several jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

Accounting for uncertainty in income taxes prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities.

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2019, we had federal net operating loss ("NOL") carryforwards of $383.9 million. Generally, these NOLs are available to reduce future taxable income and the related income tax liability subject to the limitations set forth in Sections 382 and 172. Recently passed legislation temporarily suspends the Section 172 limitation for NOLs arising in a tax year beginning in 2018, 2019 or 2020, allowing these NOLs to fully offset taxable income, and the same legislation also allows these NOLs to be carried back five years. However, these NOLs are subject to an annual Section 382 limitation as a result of the ownership change that occurred in connection with our stock offerings in September, November and December of 2019, combined with ownership shifts over the rolling three-year period. Accordingly, substantially all of our NOLs at the time of the ownership changes will be limited to use at a rate of $700 thousand per year, with the pre-2018 NOLs being subject to expiration between December 31, 2019 and the tax year 2037. Given our annual Section 382 limitation and the uncertainty of our ability to generate taxable income, a valuation allowance of $105.2 million has been recorded for the year ended December 31, 2019 against the deferred tax assets, reduced by the amount of the deferred tax liability.

Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. See Note 16 – “Income Taxes” to our consolidated financial statements.

Properties Acquired in Business Combinations

When sufficient market data is not available, we determine the fair values of proved and unproved oil and gas properties acquired in transactions accounted for as business combinations by preparing estimates of cash flows from the production of crude oil, NGL and natural gas 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 the fair value assigned to proved reserves, future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. When estimating and valuing unproved reserves, discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors. For other assets acquired in business combinations, we use a combination of available cost and market data and/or estimated cash flows to determine the fair values

Recent Accounting Pronouncements

In November 2019, the FASB issued ASU 2019-12 – Income Taxes (“Topic 740”). The amendments in ASU 2019-12 are part of an initiative to reduce complexity in accounting standards and simplify the accounting for income taxes by removing certain exceptions from Topic 740. The amendments in this update are effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. The provisions of this update are not expected to have a material impact on the Company’s financial position or results of operations.

In August 2018, the FASB issued ASU 2018-13 – Fair Value Measurement (“Topic 820”). The amendments in ASU 2018-13 modify the disclosure requirements on fair value measurements in Topic 820. The amendments in this update are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The provisions of this update are not expected to have a material impact on the Company’s financial position or results of operations.

Off Balance Sheet Arrangements

We may from time to time enter into short-term off-balance sheet arrangements that can give rise to off-balance sheet obligations, such as short-term drilling rig contracts and operating lease agreements, all of which are customary in the oil and gas industry. Other than the off-balance sheet delay rental arrangements included in the commitments and contingencies table under Note 14 – “Commitments and Contingencies”, we have no other arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources as of December 31, 2019.

Item 8. *Financial Statements and Supplementary Data*

The financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented on pages F-1 through F-37 of this Form 10-K.

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

An evaluation was performed under the supervision and with the participation of the Company's senior management, including the Company's President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") as of December 31, 2019, the end of the period covered by this report. Based on that evaluation, the Company's management, including the President and Chief Executive Officer and the Chief Financial Officer, concluded that the Company's disclosure controls and procedures were effective as of such date to ensure that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control Over Financial Reporting

As noted under "*Management's report on internal control over financial reporting*", management's evaluation of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the Will Energy properties acquired on October 25, 2019 or the White Star properties acquired on November 1, 2019. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. The Company is in the process of integrating Will Energy's and White Star's internal controls over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. There was no change in our internal control over financial reporting during the fiscal quarter ended December 31, 2019 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *2013 Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in *2013 Internal Control-Integrated Framework*, the Company's management concluded that its internal control over financial reporting was effective as of December 31, 2019. Management's evaluation of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the properties acquired in the Will Energy and White Star acquisitions. Will Energy's total assets represented approximately 10% of the Company's consolidated total assets at December 31, 2019, and Will Energy's total operating revenues represented approximately 2% of the Company's consolidated total operating revenue for the year ended December 31, 2019. White Star's total assets represented approximately 48% of the Company's consolidated total assets at December 31, 2019, and White Star's total operating revenues represented approximately 28% of the Company's consolidated total operating revenue for the year ended December 31, 2019.

Grant Thornton LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Form 10-K, has audited the effectiveness of our internal control over financial reporting as of December 31, 2019, as stated in their report included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of Contango Oil & Gas Company (a Texas corporation) and subsidiaries (the “Company”) as of December 31, 2019, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements of the Company as of and for the year ended December 31, 2019, and our report dated March 30, 2020, expressed an unqualified opinion on those financial statements.

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

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

Our audit of, and opinion on, the Company’s internal control over financial reporting does not include the internal control over financial reporting of White Star Petroleum, LLC and Will Energy Corporation, which were acquired by two wholly-owned subsidiaries of the Company, whose financial statements reflect total assets and revenues constituting 48 percent and 28 percent, and 10 percent and 2 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2019. As indicated in Management’s Report, assets of White Star Petroleum, LLC and Will Energy Corporation were acquired during 2019. Management’s assertion on the effectiveness of the Company’s internal control over financial reporting excluded internal control over financial reporting of White Star Petroleum, LLC and Will Energy Corporation.

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

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

/s/ GRANT THORNTON LLP

Houston, Texas
March 30, 2020

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

None.

PART III

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

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2020 Annual Meeting of Stockholders (the "Proxy Statement") under the headings "Proposal 1: Election of Directors", "Executive Compensation", "Delinquent Section 16(a) Reports" (if necessary) and "Corporate Governance and our Board" and is incorporated herein by reference. The Proxy Statement will be filed with the SEC pursuant to Regulation 14A of the Exchange Act, not later than 120 days after December 31, 2019.

Code of Ethics

In January 2014, our board of directors adopted our current Code of Business Conduct and Ethics ("Code of Conduct") which applies to all directors, officers and employees of the Company, including our principal executive, principal financial and principal accounting officers, or persons performing similar functions. Our Code of Conduct is available on the Company's website at www.contango.com. Changes in and waivers to the Code of Conduct for the Company's directors, chief executive officer and certain senior financial officers will be posted on the Company's website within four business days and maintained for at least 12 months. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this report.

Item 11. ***Executive Compensation***

The information required under Item 11 of Form 10-K will be contained in the Proxy Statement under the heading "Executive Compensation" and is incorporated herein by reference.

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

Other than as set forth below, the information required under Item 12 of Form 10-K will be contained in the Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

Securities authorized for issuance under equity compensation plans

The following table sets forth information about our equity compensation plans at December 31, 2019:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights (1)	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders			
Second Amended and Restated 2009 Incentive Compensation Plan	204,474 (2)	$ —	1,480,389
Equity plans not approved by security holders			
2005 Stock Incentive Plan ("Crimson Plan")	20,964	$ 58.53	—

(1) The weighted-average exercise price does not take into account the shares issuable upon vesting of outstanding performance stock units, which have no exercise price.

(2) Represents shares issuable upon the vesting of performance stock units awarded under the plan. The actual number of shares that a grant recipient receives at the end of the period may range from 0% to 300% of the target number of shares.

The 2005 Stock Incentive Plan was adopted by our Board in conjunction with the merger with Crimson Exploration, Inc. (“Crimson”). Prior to such merger, it had been approved by Crimson Stockholders. The plan expired on February 25, 2015, and therefore no additional shares are available for grant.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information required under Item 13 of Form 10-K will be contained in the Proxy Statement under the headings “Corporate Governance and our Board”, “Transactions with Related Persons” and “Executive Compensation” and is incorporated herein by reference.

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

The information required under Item 14 of Form 10-K will be contained in the Proxy Statement under the subheading “Principal Accountant Fees and Services” and is incorporated herein by reference.

GLOSSARY OF SELECTED TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this report.

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

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Boe. Barrel of oil equivalent per day determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

Boe/d. Boe per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

IP 30. The average daily hydrocarbon production rate of the initial 30 days of full commercial production. IP 30 average daily production rates are subject to natural and mechanical declines and are accordingly not comparable to the average daily production rate over the life of the well.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMBbls. million barrels of oil or other liquid hydrocarbons.

MMBtu. million British Thermal Units. One MMBtu equates to approximately one Mcf.

MMcf. million cubic feet of natural gas.

MMcfe. million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

MMcfe/d. Mmcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed producing reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(6) of Regulation S-X, which defines proved developed reserves as reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as the estimated quantities of oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

The area of a reservoir considered proved includes (A) the area identified by drilling and limited by fluid contacts, if any, and (B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geological and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geological, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when successful testing by a pilot project, the operation of an installed program in the reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and the project has been approved for development by all necessary parties and entities, including governmental entities.

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(31) of Regulation S-X, which defines proved undeveloped reserves as 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 the specific circumstances, justify a longer time. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir, or by other evidence using reliable technology establishing reasonable certainty.

PV-10. A non-GAAP financial measure that represents the present value, discounted at 10% per year, of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes or non-property related expenses such as general and administrative expenses and debt service or depreciation, depletion and amortization on future net revenues. Neither PV-10 nor Standardized Measure of Discounted Net Cash Flows represents an estimate of fair market value of natural gas and oil properties. PV-10 is used by the industry as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

Reservoir. 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.

Total Measured Depth or TMD. The total measured drilled vertical and horizontal depth of a well.

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

Working interest or WI. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

PART IV

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

(a) Financial Statements and Schedules:

The financial statements are set forth in pages F-1 to F-29 of this Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibits:

The following is a list of exhibits filed as part of this Form 10-K. Where so indicated by a footnote, exhibits, which were previously filed, are incorporated herein by reference.

Exhibit Number	Description
2.1	Agreement and Plan of Merger, among Contango Oil & Gas Company, Contango Acquisition, Inc. and Crimson Exploration Inc., dated as of April 29, 2013 (filed as Exhibit 2.1 to the Company's report on Form 8-K, dated as of April 29, 2013, as filed with the Securities and Exchange Commission on May 1, 2013, and incorporated by reference herein).
2.2	Asset Purchase and Sale Agreement, dated as of September 30, 2019, by and among Contango Oil & Gas Company, White Star Petroleum, LLC, White Star Petroleum II, LLC, White Star Petroleum Operating, LLC and, solely for the purposes described therein, White Star Petroleum Holdings, LLC and WSP Finance Corporation (filed as Exhibit 2.1 to the Company's Report on Form 8-K dated September 30, 2019, as filed with the Securities and Exchange Commission on October 1, 2019 and incorporated by reference herein).
3.1	Amended and Restated Certificate of Formation of Contango Oil & Gas Company (filed as Exhibit 3.3 to the Company's Report on Form 8-K dated June 14, 2019, as filed with the Securities and Exchange Commission on June 14, 2019 and incorporated by reference herein).
3.2	Bylaws of Contango Oil & Gas Company (filed as Exhibit 3.4 to the Company's Report on Form 8-K dated June 14, 2019, as filed with the Securities and Exchange Commission on June 14, 2019 and incorporated by reference herein).
3.3	Statement of Resolution Establishing Series of Shares Designated Series A Contingent Convertible Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated September 12, 2019, as filed with the Securities and Exchange Commission on September 18, 2019 and incorporated by reference herein).
3.4	Statement of Resolution Establishing Series of Shares Designated Series B Contingent Convertible Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated October 30, 2019, as filed with the Securities and Exchange Commission on November 5, 2019 and incorporated by reference herein).
3.5	Certificate of Amendment to the Amended and Restated Certificate of Formation of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated December 12, 2019, as filed with the Securities and Exchange Commission on December 16, 2019 and incorporated by reference herein).
3.6	Statement of Resolution Establishing Series of Shares Designated Series C Contingent Convertible Preferred Stock of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Report on Form 8-K dated December 19, 2019, as filed with the Securities and Exchange Commission on December 23, 2019 and incorporated by reference herein).
4.1	Facsimile of common stock certificate of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's Form 10-SB Registration Statement, as filed with the Securities and Exchange Commission on October 16, 1998, and incorporated by reference herein).
4.2	Registration Rights Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, OCM Crimson Holdings, LLC and OCM GW Holdings, LLC (filed as Exhibit 10.9 to the Company's report on Form 8-K, dated as of April 29, 2013, as filed with the Securities and Exchange Commission on May 1, 2013, and incorporated by reference herein).

Exhibit Number	Description
4.3	Rights Agreement, dated as of August 1, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated August 1, 2018, as filed with the Securities and Exchange Commission on August 2, 2018, and incorporated by reference herein).
4.4	Amendment to the Rights Agreement, dated as of November 21, 2018, between Contango Oil & Gas Company, as the Company, and Continental Stock Transfer & Trust Company, as Rights Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated November 21, 2018, as filed with the Securities and Exchange Commission on November 21, 2018, and incorporated by reference herein).
4.5	Description of Securities registered under Section 12 of the Exchange Act. †
10.1*	Amended and Restated 2005 Stock Incentive Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated as of October 1, 2013, as filed with the Securities and Exchange Commission on October 2, 2013, and incorporated by reference herein).
10.2*	Contango Oil & Gas Company Amended and Restated 2009 Incentive Compensation Plan (filed as an exhibit to the Company's Schedule 14A on Definitive Proxy Statement for 2014, as filed with the Securities and Exchange Commission on April 11, 2014, and incorporated by reference herein).
10.3	First Amended and Restated Limited Liability Company Agreement dated as of March 31, 2012 between Contango Oil & Gas Company and Exaro Energy III LLC (filed as Exhibit 10.1 to the Company's report on Form 8-K, dated as of March 31, 2012, as filed with the Securities and Exchange Commission on April 5, 2012, and incorporated by reference herein).
10.4	Second Amended and Restated Limited Liability Company Agreement dated as of February 1, 2013 between Contango Oil & Gas Company and Exaro Energy III LLC (filed as Exhibit 10.4 to the Company's report on Form 10-K for the fiscal year ended December 31, 2018, as filed with the Securities and Exchange Commission on March 18, 2019, and incorporated by reference herein).
10.5	Participation Agreement covering OCS-G 33596, Vermilion 170, dated as of July 1, 2010 between Republic Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.51 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.6	Participation Agreement covering Tuscaloosa Marine Shale, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc. (filed as Exhibit 10.56 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.7	Letter Agreement dated as of June 8, 2012 between Juneau Exploration LP and Contango Operators, Inc. (filed as Exhibit 10.57 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.8	Agreement to Purchase Overriding Royalty Interest, dated March 1, 2010 between Contango Offshore Exploration LLC and Juneau Exploration LP (filed as Exhibit 10.60 to the Company's report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012, and incorporated by reference herein).
10.9*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and E. Joseph Grady (filed as Exhibit 10.12 to the Company's report on Form 10-K for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on March 15, 2017, and incorporated by reference herein).
10.10*	Contango Oil & Gas Company Director Compensation Plan (filed as Exhibit 10.4 to the Company's report on Form 10-Q for the quarter ended March 21, 2017, as filed with the Securities and Exchange Commission on May 10, 2017, and incorporated by reference herein).
10.11*	Form of Contango Oil and Gas Company Stock Award Agreement (employees) (filed as Exhibit 10.7 to the Company's report on Form 10-Q for the quarter ended September 30, 2016, as filed with the Securities and Exchange Commission on November 3, 2016, and incorporated by reference herein).

Exhibit Number	Description
10.12*	Form of Contango Oil and Gas Company Stock Award Agreement (executives) (filed as Exhibit 10.8 to the Company's report on Form 10-Q for the quarter ended September 30, 2016, as filed with the Securities and Exchange Commission on November 3, 2016, and incorporated by reference herein).
10.13	Credit Agreement, dated September 17, 2019, by and among Contango Oil & Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and each of JPMorgan Chase Bank, N.A., Royal Bank of Canada and Cadence Bank, N.A. (filed as Exhibit 10.3 to the Company's Report on Form 8-K dated September 12, 2019, as filed with the Securities and Exchange Commission on September 18, 2019 and incorporated by reference herein).
10.14	Registration Rights Agreement, dated September 17, 2019, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.2 to the Company's Report on Form 8-K dated September 12, 2019, as filed with the Securities and Exchange Commission on September 18, 2019 and incorporated by reference herein).
10.15	Registration Rights Agreement, dated November 1, 2019, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.2 to the Company's Report on Form 8-K dated October 30, 2019, as filed with the Securities and Exchange Commission on November 5, 2019 and incorporated by reference herein).
10.16	First Amendment to Credit Agreement, dated November 1, 2019, by and among Contango Oil & Gas Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders Signatory hereto (filed as Exhibit 10.3 to the Company's Report on Form 8-K dated October 30, 2019, as filed with the Securities and Exchange Commission on November 5, 2019 and incorporated by reference herein).
10.17	Registration Rights Agreement, dated December 23, 2019, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.3 to the Company's Report on Form 8-K dated December 19, 2019, as filed with the Securities and Exchange Commission on December 23, 2019 and incorporated by reference herein).
10.18	Registration Rights Agreement, dated December 23, 2019, by and among Contango Oil & Gas Company and each of the parties set forth in Schedule A thereto (filed as Exhibit 10.4 to the Company's Report on Form 8-K dated December 19, 2019, as filed with the Securities and Exchange Commission on December 23, 2019 and incorporated by reference herein).
21.1	List of Subsidiaries. †
21.2	Organizational Chart. †
23.1	Consent of William M. Cobb & Associates, Inc. †
23.2	Consent of W.D. Von Gonten & Co. †
23.3	Consent of Grant Thornton LLP. †
24.1	Powers of Attorney (included on signature page). †
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 William M. Cobb & Associates, Inc. †
99.2	Report of W.D. Von Gonten and Company. †

* Indicates a management contract or compensatory plan or arrangement

† Filed herewith

†† Furnished herewith

Item 16. ***Form 10-K Summary***

None.

SIGNATURES

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

CONTANGO OIL & GAS COMPANY

By: /s/ WILKIE S. COLYER Date: March 30, 2020

Wilkie S. Colyer

President and Chief Executive Officer

POWER OF ATTORNEY

Know all men by these presents, that the undersigned constitutes and appoints Wilkie S. Colyer and E. Joseph Grady as his true and lawful attorneys-in-fact and agent, with full power of substitution for him and in his name, place and stead, in any and all capacities to sign any and all amendments or supplements to this Annual Report on Form 10-K, and to file the same, and with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ WILKIE S. COLYER Wilkie S. Colyer	President and Chief Executive Officer (principal executive officer) and Director	March 30, 2020
/s/ E. JOSEPH GRADY E. Joseph Grady	Chief Financial Officer (principal financial officer) and Chief Accounting Officer (principal accounting officer)	March 30, 2020
/s/ JOHN C. GOFF John C. Goff	Director	March 30, 2020
/s/ JOSEPH J. ROMANO Joseph J. Romano	Director	March 30, 2020
/s/ B. A. BERILGEN B. A. Berilgen	Director	March 30, 2020
/s/ B. JAMES FORD B. James Ford	Director	March 30, 2020
/s/ ELLIS L. MCCAIN Ellis L. McCain	Director	March 30, 2020

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Contango Oil & Gas Company (a Texas corporation) and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of operations, cash flows, and shareholders' equity for each of the two years in the period ended December 31, 2019, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 30, 2020 expressed an unqualified opinion.

Change in accounting principle

As discussed in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for leases in the year ended December 31, 2019 due to the adoption of FASB Accounting Standards Codification Topic 842, Leases.

Basis for opinion

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

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

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2002.

Houston, Texas
March 30, 2020

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except shares)

	December 31, 2019	December 31, 2018
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,624	$ —
Accounts receivable, net	39,567	11,531
Prepaid expenses	1,191	1,303
Current derivative asset	3,819	4,600
Inventory	150	—
Other	36	—
Total current assets	46,387	17,434
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,306,916	1,095,417
Unproved properties	27,619	34,612
Other property and equipment	1,655	1,314
Accumulated depreciation, depletion and amortization	(1,045,070)	(898,169)
Total property, plant and equipment, net	291,120	233,174
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	6,766	5,743
Long-term derivative asset	357	—
Deferred tax asset	—	424
Debt issuances costs	3,311	357
Right-of-use lease assets	5,885	—
Total other non-current assets	16,319	6,524
TOTAL ASSETS	$ 353,826	$ 257,132
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 104,593	$ 39,506
Current derivative liability	3,951	422
Current asset retirement obligations	2,003	1,329
Current portion of long-term debt	—	60,000
Total current liabilities	110,547	101,257
NON-CURRENT LIABILITIES:		
Long-term debt	72,768	—
Long-term derivative liability	2,020	—
Asset retirement obligations	49,662	12,168
Lease liabilities	2,789	—
Other long term liabilities	—	3,318
Total non-current liabilities	127,239	15,486
Total liabilities	237,786	116,743
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
SHAREHOLDERS' EQUITY:		
Series C convertible preferred stock, $0.04 par value, 2,700,000 shares authorized, issued and outstanding at December 31, 2019	108	—
Common stock, $0.04 par value, 200 million shares authorized, 128,985,146 shares issued and 128,977,816 shares outstanding at December 31, 2019, 39,617,442 shares issued and 34,158,492 shares outstanding at December 31, 2018	5,148	1,573
Additional paid-in capital	471,778	339,981
Treasury shares at cost (7,330 shares at December 31, 2019 and 5,458,950 shares at December 31, 2018)	(18)	(129,030)
Accumulated deficit	(360,976)	(72,135)
Total shareholders' equity	116,040	140,389
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 353,826	$ 257,132

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31, 2019	2018
REVENUES:		
Oil and condensate sales	$ 44,705	$ 34,413
Natural gas sales	22,380	29,824
Natural gas liquids sales	9,427	12,850
Total revenues	76,512	77,087
EXPENSES:		
Operating expenses	33,205	25,552
Exploration expenses	1,003	1,637
Depreciation, depletion and amortization	39,807	41,657
Impairment and abandonment of natural gas and oil properties	128,290	103,732
General and administrative expenses	24,938	24,157
Total expenses	227,243	196,735
OTHER INCOME (EXPENSE):		
Gain (loss) from investment in affiliates (net of income taxes)	742	(12,721)
Gain from sale of assets and return on investments	518	13,224
Interest expense	(8,596)	(5,548)
Gain (loss) on derivatives, net	(3,357)	1,939
Other income	1,848	1,306
Total other income	(8,845)	(1,800)
NET LOSS BEFORE INCOME TAXES	(159,576)	(121,448)
Income tax provision	(220)	(120)
NET LOSS ATTRIBUTABLE TO COMMON STOCK	$ (159,796)	$ (121,568)
NET LOSS PER SHARE:		
Basic	$ (2.95)	$ (4.69)
Diluted	$ (2.95)	$ (4.69)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
Basic	54,136	25,945
Diluted	54,136	25,945

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (159,796)	$ (121,568)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	39,807	41,657
Impairment of natural gas and oil properties	126,964	103,164
Amortization of debt issuance costs	144	—
Deferred income taxes	424	—
Gain on sale of assets	(518)	(13,224)
Loss (gain) from investment in affiliates	(742)	12,721
Stock-based compensation	2,352	4,766
Unrealized loss (gain) on derivative instruments	5,973	(5,421)
Changes in operating assets and liabilities:		
Decrease (increase) in accounts receivable & other	(9,903)	1,316
Decrease in prepaid expenses	451	589
Increase (decrease) in accounts payable & advances from joint owners	10,739	(2,433)
Increase (decrease) in other accrued liabilities	13,019	(1,209)
Increase in income taxes receivable, net	(85)	—
Increase (decrease) in income taxes payable, net	(153)	40
Other	(6,966)	3,079
Net cash provided by operating activities	$ 21,710	$ 23,477
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	$ (42,737)	$ (58,947)
Acquisition of natural gas & oil properties	(112,075)	—
Additions to furniture & equipment	(53)	(42)
Sale of oil and gas properties	10	27,805
Sale of energy credits	—	497
Net cash used in investing activities	$ (154,855)	$ (30,687)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under Credit Agreement	$ 256,923	$ 236,611
Repayments under Credit Agreement	(244,154)	(261,992)
Net proceeds from equity offerings	125,710	33,038
Reissuance of treasury stock	(255)	(447)
Debt issuance costs	(3,455)	—
Net cash provided by financing activities	$ 134,769	$ 7,210
NET DECREASE IN CASH AND CASH EQUIVALENTS	$ 1,624	$ —
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 1,624	$ —

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
For the twelve months ended December 31, 2019
(in thousands, except share amounts)

	Preferred Stock		Common Stock		Additional Paid-in Capital	Treasury Stock	Accumulated Deficit	Total Shareholders' Equity
	Shares	Amount	Shares	Amount				
					(unaudited)			
Balance at December 31, 2018	—	$ —	34,158,492	$ 1,573	$ 339,981	$ (129,030)	$ (72,135)	$ 140,389
Equity offering - common stock	—	—	—	—	(86)	—	—	(86)
Treasury shares at cost	—	—	(49,415)	—	—	(186)	—	(186)
Restricted shares activity	—	—	307,650	12	(12)	—	—	—
Stock-based compensation	—	—	—	—	1,052	—	—	1,052
Net loss	—	—	—	—	—	—	(8,618)	(8,618)
Balance at March 31, 2019	—	$ —	34,416,727	$ 1,585	$ 340,935	$ (129,216)	$ (80,753)	$ 132,551
Equity offering - common stock	—	—	—	—	45	—	—	45
Treasury shares at cost	—	—	(16,133)	—	—	(50)	—	(50)
Restricted shares activity	—	—	42,249	2	(2)	—	—	—
Stock-based compensation	—	—	—	—	585	—	—	585
Net loss	—	—	—	—	—	—	(4,961)	(4,961)
Balance at June 30, 2019	—	$ —	34,442,843	$ 1,587	$ 341,563	$ (129,266)	$ (85,714)	$ 128,170
Equity offering - preferred stock	789,474	32	—	—	7,420	—	—	7,452
Equity offering - common stock	—	—	45,922,870	2,058	44,181	—	—	46,239
Treasury shares reissuance	—	—	5,524,498	(221)	—	129,266	(129,045)	—
Restricted shares activity	—	—	(25,748)	(1)	1	—	—	—
Stock-based compensation	—	—	—	—	558	—	—	558
Net loss	—	—	—	—	—	—	(7,838)	(7,838)
Balance at September 30, 2019	789,474	$ 32	85,864,463	$ 3,423	$ 393,723	$ —	$ (222,597)	$ 174,581
Equity offering - preferred stock	3,802,838	152	—	—	26,154	—	—	26,306
Equity offering - common stock	—	—	19,000,000	760	44,942	—	—	45,702
Conversion of preferred stock to common stock	(1,892,312)	(76)	18,923,120	757	(629)	—	—	52
Treasury shares at cost	—	—	(7,330)	—	—	(18)	—	(18)
Restricted shares activity	—	—	(27,437)	(1)	1	—	—	—
Stock-based compensation	—	—	—	—	158	—	—	158
Will Energy and Juneau acquisitions	—	—	5,225,000	209	7,429	—	—	7,638
Net loss	—	—	—	—	—	—	(138,379)	(138,379)
Balance at December 31, 2019	2,700,000	$ 108	128,977,816	$ 5,148	$ 471,778	$ (18)	$ (360,976)	$ 116,040

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
For the twelve months ended December 31, 2018
(in thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total Shareholders' Equity
				(unaudited)		
Balance at December 31, 2017	25,505,715	$ 1,223	$ 302,527	$ (128,583)	$ 49,433	$ 224,600
Treasury shares at cost	(16,032)	—	—	(71)	—	(71)
Restricted shares activity	206,114	8	(8)	—	—	—
Stock-based compensation	—	—	1,424	—	—	1,424
Net income	—	—	—	—	937	937
Balance at March 31, 2018	25,695,797	$ 1,231	$ 303,943	$ (128,654)	$ 50,370	$ 226,890
Treasury shares at cost	(33,703)	—	—	(124)	—	(124)
Restricted shares activity	77,188	4	(4)	—	—	—
Stock-based compensation	—	—	1,584	—	—	1,584
Net loss	—	—	—	—	(7,178)	(7,178)
Balance at June 30, 2018	25,739,282	$ 1,235	$ 305,523	$ (128,778)	$ 43,192	$ 221,172
Treasury shares at cost	(27,860)	—	—	(175)	—	(175)
Restricted shares activity	(127,314)	(6)	6	—	—	—
Stock-based compensation	—	—	764	—	—	764
Net loss	—	—	—	—	(81,524)	(81,524)
Balance at September 30, 2018	25,584,108	$ 1,229	$ 306,293	$ (128,953)	$ (38,332)	$ 140,237
Equity offering costs	8,596,068	344	32,694	—	—	33,038
Treasury shares at cost	(13,600)	—	—	(77)	—	(77)
Restricted shares activity	(8,084)	—	—	—	—	—
Stock-based compensation	—	—	994	—	—	994
Net loss	—	—	—	—	(33,803)	(33,803)
Balance at December 31, 2018	34,158,492	$ 1,573	$ 339,981	$ (129,030)	$ (72,135)	$ 140,389

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, “Contango” or the “Company”) is a Houston, Texas based independent oil and natural gas company, with regional offices in Oklahoma City and Stillwater, Oklahoma. The Company’s business is to maximize production and cash flow from its offshore properties in the shallow waters of the Gulf of Mexico (“GOM”) and onshore Texas, Oklahoma, Louisiana and Wyoming properties and use that cash flow to explore, develop, exploit and acquire oil and natural gas properties across the United States. On June 14, 2019, following approval by the Company’s stockholders at the 2019 annual meeting of stockholders, Contango changed its state of incorporation from the State of Delaware to the State of Texas and increased its number of authorized shares of common stock from 50 million to 100 million. On December 12, 2019, following approval by the Company’s stockholders by executed and delivered written consent, Contango increased its number of authorized shares of common stock from 100 million to 200 million.

In December 2019, the Company entered into a Joint Development Agreement with Juneau Oil & Gas, LLC (“Juneau”), which provides the Company the right to acquire an interest in up to six of Juneau’s exploratory prospects located in the Gulf of Mexico. See Note 4 – “Acquisitions and Dispositions” for more information.

In September 2019, the Company entered into unrelated purchase agreements with Will Energy Corporation (“Will Energy”) and White Star Petroleum, LLC and certain of its affiliates (collectively, “White Star”) to purchase certain producing assets and undeveloped acreage, primarily in Oklahoma. These transactions closed during the three months ended December 31, 2019. See Note 4 – “Acquisitions and Dispositions” for more information.

Also in September 2019, the Company entered into a new revolving credit agreement with JPMorgan Chase Bank, N.A. and other lenders (the “Credit Agreement”). In connection with the entry into the Credit Agreement, the Company repaid all obligations outstanding on, and terminated, its previous credit agreement with Royal Bank of Canada, which matured on October 1, 2019. The new Credit Agreement was amended on November 1, 2019, in conjunction with the closing of the Will Energy and White Star acquisitions, to add two additional lenders and increase the borrowing base thereunder from $65 million to $145 million. See Note 13 – “Long-Term Debt” for more information.

From the Company’s initial entry into the Southern Delaware Basin in 2016 and through early 2019, the Company has focused on the development of its initial 6,500 net acre position in Pecos County, Texas (“Bullseye”), and in December 2018, the Company purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of its existing acreage (“NE Bullseye”) for approximately $7.5 million. The Company paid $3.2 million cash in December 2018, with the remaining cash balance paid in installments in March and October of 2019. Contango’s 2019 drilling program included the completion of one well previously drilled in the Bullseye area, the drilling and completion of a second Bullseye well, and the drilling and completion of three wells in the NE Bullseye area. As of December 31, 2019, the Company was producing from seventeen wells over its approximate 18,600 gross (8,000 net) acre position in West Texas, prospective for the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. In December 2019, the Company began completion operations on its fourth NE Bullseye well, which began producing in January 2020. Also in December 2019, the Company completed and brought on production a Garfield County, Oklahoma well in the Company’s Central Oklahoma region, which it acquired in connection with the White Star acquisition. See Note 4 – “Acquisitions and Dispositions” for more information.

In response to low commodity prices and a related window of opportunity to acquire producing properties on very attractive terms, the Company finished its 2019 drilling program which was designed to only preserve core areas of its West Texas play, and thereafter focused on identifying, evaluating and acquiring producing reserves. As a result, the Company was successful in closing the Will Energy and White Star acquisitions in the fourth quarter of 2019. For 2020, the Company believes that a continuing low price environment and a shortage of capital available to the industry may present more opportunities to acquire additional producing properties that could provide strong production, cash flow and future development potential at attractive rates of return. The Company plans to be active in pursuing such acquisition opportunities and then allowing its technical teams to leverage their experience and expertise to work on increasing returns through production enhancement, cost reduction and future development of the unproved drilling locations that come with the production acquired. The Company can provide no assurances that it will acquire any producing property opportunities on attractive terms, or at all, or that it will realize the expected benefits of any acquisition. The Company also currently plans to limit its 2020 drilling program to only address leasehold commitments and preserve core acreage in its areas, while complementing that strategy with one to two relatively low cost, high-potential offshore exploratory wells on prospects recently acquired from Juneau. See Note 4 – “Acquisitions and Dispositions” for more information. The Company will continue to make balance sheet strength a priority in 2020 as it utilizes excess cash flow to reduce debt and increase its capacity to quickly react to acquisition opportunities.

The Company is also currently undertaking an extensive review of all of its producing areas in light of the commodity price environment, and where determined justified and operationally feasible, the Company plans to potentially shut in or curtail unhedged production. Because of the Company’s low debt profile and borrowing cost of capital, the Company believes it may be able to temporarily shut in or curtail higher cost production when there is a decline in the commodity markets. The Company is also currently re-evaluating the economic justification for proceeding with the production-enhancing workover program originally scheduled for the first half of 2020. The limited onshore development drilling planned for 2020 is also being re-evaluated.

In November 2018, the Company completed an underwritten public offering of 8,596,068 shares of its common stock for net proceeds of approximately $33.0 million, which were used to reduce borrowings under its former credit facility, fund the initial purchase of the NE Bullseye acreage and provide funding for its 2019 capital expenditure program.

In September 2019, the Company completed an underwritten public offering (the “September Public Offering”) of 51,447,368 shares of common stock (of which 5,524,498 were reissued treasury shares) for net proceeds of approximately $46.2 million, after deducting the underwriting discount and fees and expenses. Net proceeds from the September Public Offering were used to fund the cash portion of the purchase price for the Will Energy acquisition and to reduce borrowings under the Company’s former revolving credit facility.

In conjunction with the September Public Offering, the Company also entered into a purchase agreement with affiliates of John C. Goff, a director and significant shareholder, and current chairman, of the Company, to issue and sell in a private placement (the “Series A Private Placement”) 789,474 shares of Series A contingent convertible preferred stock, which resulted in net proceeds of approximately $7.5 million. In November 2019, the Company completed a private placement of 1,102,838 shares of Series B contingent convertible preferred stock of the Company, which resulted in net proceeds of approximately $21.0 million (the “Series B Private Placement”). Net proceeds from the Series A Private Placement were used to fund a portion of the purchase price and related transaction expenses for the Will Energy acquisition, and net proceeds from the Series B Private Placement were used to fund a portion of the purchase price and related transaction expenses for the White Star acquisition.

In the fourth quarter of 2019, the Company obtained approval from the holders of a majority of the voting power of the Company’s capital stock to increase the number of common shares authorized for issuance from 100 million to 200 million common shares, at which time the Series A preferred shares automatically converted into 7,894,740 shares of common stock, the Series B preferred shares automatically converted into 11,028,380 shares of common stock, and the outstanding preferred shares were cancelled.

In December 2019, the Company also completed a private placement offering (the “December Offering”) of 19,000,000 shares of common stock for net proceeds of approximately $45.7 million, after deducting the underwriting discount and fees and expenses. In conjunction with the December Offering, the Company also completed a private placement of 2,340,000 shares of Series C contingent convertible preferred stock (the “Series C Private Placement”) with affiliates of Mr. Goff, Mr. Wilkie S. Colyer, Jr., our chief executive officer, and others, which resulted in net proceeds of approximately $5.6 million. An additional 360,000 Series C contingent convertible preferred shares were issued in a private placement to the placement agents for the December Offering and Series C Private Placement, as partial consideration for their services. Net proceeds from the December Offering and Series C Private Placement will be used for general corporate purposes, including capital expenditures under the Company’s Joint Development Agreement with Juneau. See Note 4 – “Acquisitions and Dispositions” for more information.

The Series C preferred shares are a new class of equity security that ranks equal to the common shares with respect to dividend rights and rights upon liquidation. The Series C preferred shares have no voting rights. Upon approval by the holders of a majority of the voting power of the Company’s capital stock, each Series C preferred share will then automatically convert into one common share and, upon conversion, the outstanding Series C preferred shares will be cancelled.

Additionally, the Company has (i) a 37% equity investment in Exaro Energy III LLC ("Exaro") that is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; (ii) operated properties producing from various conventional formations in various counties along the Texas Gulf Coast; and (iii) operated producing properties in the Haynesville Shale, Mid Bossier and James Lime formations in East Texas.

2. Summary of Significant Accounting Policies

Basis of Presentation

The Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. All wholly-owned subsidiaries are consolidated.

Other Investments

The Company has two seats on the board of directors of Exaro and has significant influence, but not control, over the company. As a result, the Company's 37% ownership in Exaro is accounted for using the equity method. Under the equity method, the Company's proportionate share of Exaro's net income increases the balance of its investment in Exaro, while a net loss or payment of dividends decreases its investment. In the consolidated statement of operations, the Company's proportionate share of Exaro's net income or loss is reported as a single line-item in Gain (loss) from investment in affiliates (net of income taxes).

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of 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 periods. The most significant estimates include oil, natural gas, and NGL revenues, income taxes, stock-based compensation, reserve estimates, impairment of natural gas and oil properties, valuation of derivatives, asset retirement obligations, accrued liabilities and purchase price allocations. Actual results could differ from those estimates.

Revenue Recognition

Adoption of ASC 606

As of January 1, 2018 the Company adopted Accounting Standards Codification Topic 606 – Revenue from Contracts with Customers ("ASC 606"), which supersedes the revenue recognition requirements and industry-specific guidance under Accounting Standards Codification Top 605 – Revenue Recognition ("ASC 605"). The Company adopted ASC 606 using the modified retrospective method which allows the Company to apply the new standard to all new contracts entered into after December 31, 2017 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance prior to December 31, 2017. The Company identified no material impact on its historical revenues upon initial application of ASC 606, and as such has not recognized any cumulative catch-up effect to the opening balance of the Company's shareholders' equity as of January 1, 2018. 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.

Revenue from Contracts with Customers

Sales of oil, condensate, natural gas and natural gas liquids ("NGLs") are recognized at the time control of the products are transferred to the customer. Based upon the Company's current purchasers' past experience and expertise in the market, collectability is probable, and there have not been payment issues with the Company's purchasers over the past year or currently. Generally, the Company's gas processing and purchase agreements indicate that the processors take control of the gas at the inlet of the plant and that control of residue gas is returned to the Company at the outlet of the plant. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs. The Company delivers oil and condensate to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product.

When sales volumes exceed the Company's entitled share, a production imbalance occurs. If production imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. Production imbalances have not had and currently do not have a material impact on the financial statements, and this did not change with the adoption of ASC 606.

Transaction Price Allocated to Remaining Performance Obligations

Generally, the Company's contracts have an initial term of one year or longer but continue month to month unless written notification of termination in a specified time period is provided by either party to the contract. The Company has used the practical expedient in ASC 606 which states that the Company is not required to disclose that transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligation is not required.

Contract Balances

The Company receives purchaser statements from the majority of its customers but there are a few contracts where the Company prepares the invoice. Payment is unconditional upon receipt of the statement or invoice. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606. The majority of the Company's contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of the oil or natural gas, and supply and demand conditions. The price of these commodities fluctuates to remain competitive with supply.

Prior Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements may not be received for 30 to 90 days after the date production is delivered, and therefore the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. Differences between the Company's estimates and the actual amounts received for product sales are generally recorded in the following month that payment is received. Any differences between the Company's revenue estimates and actual revenue received historically have not been significant. The Company has internal controls in place for its revenue estimation accrual process.

Impact of Adoption of ASC 606

The Company has reviewed all of its natural gas, NGLs, residue gas, condensate and oil sales contracts to assess the impact of the provisions of ASC 606. Based upon the Company's review, there were no required changes to the recording of residue gas or condensate and oil contracts. Certain NGL and natural gas contracts would require insignificant changes to the recording of transportation, gathering and processing fees as net to revenue or as an expense. The Company concluded that these minor changes were not material to its operating results on a quantitative or qualitative basis. Therefore, there was no impact to its results of operations for the twelve months ended December 31, 2019. The Company has modified procedures to its existing internal controls relating to revenue by reviewing for any significant increase in sales level, primarily on gas processing or gas purchasing contracts, on a quarterly basis to monitor the significance of gross revenue versus net revenue and expenses under ASC 606. As under previous revenue guidance, the Company will continue to review all new or modified revenue contracts on a quarterly basis for proper treatment.

Cash Equivalents

Cash equivalents are considered to be highly liquid investment grade debt investments having an original maturity of 90 days or less. As of December 31, 2019, the Company had $1.6 million in cash and cash equivalents, after transferring cash balances at the end of each day to reduce outstanding debt under the Company's revolving Credit Agreement to minimize debt service costs. Under the Company's cash management system, checks issued but not yet presented to banks by the payee frequently result in book overdraft balances for accounting purposes and are classified in accounts payable in the consolidated balance sheets. At December 31, 2019, accounts payable included $6.1 million in outstanding checks that had not been presented for payment. At December 31, 2018, accounts payable included $4.8 million in outstanding checks that had not been presented for payment.

Accounts Receivable

The Company sells natural gas, oil and NGLs to a limited number of customers. In addition, the Company participates with other parties in the operation of natural gas and oil wells. Substantially all of the Company's accounts receivables are due from either purchasers of natural gas and oil or participants in natural gas and oil wells for which the Company serves as the operator. Generally, operators of natural gas and oil properties have the right to offset future revenues against unpaid charges related to operated wells.

The allowance for doubtful accounts is an estimate of the losses in the Company's accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions and other pertinent factors. Amounts deemed uncollectible are charged to the allowance.

Accounts receivable allowance for bad debt was $1.0 and $1.0 million as of December 31, 2019 and 2018, respectively. At December 31, 2019 and 2018, the carrying value of the Company's accounts receivable approximated fair value.

Oil and Gas Properties - Successful Efforts

The Company follows the successful efforts method of accounting for its natural gas and oil activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred. Depreciation, depletion and amortization is calculated on a field by field basis using the unit of production method, with lease acquisition costs amortized over total proved reserves and other capitalized costs amortized over proved developed reserves.

Depreciation, depletion and amortization ("DD&A") of capitalized drilling and development costs of producing natural gas and oil properties, including related support equipment and facilities net of salvage value, are computed using the unit of production method on a field basis based on total estimated proved developed natural gas and oil reserves. Amortization of producing leaseholds is based on the unit of production method using total estimated proved reserves. Upon sale or retirement of properties, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized. Unit of production rates are revised whenever there is an indication of a need, but at least annually. Revisions are accounted for prospectively as changes in accounting estimates.

Other property and equipment are depreciated using the straight-line method over their estimated useful lives which range between three and 13 years.

Impairment of Oil and Gas Properties

Pursuant to GAAP, when circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows, based on the Company's estimate of future reserves, natural gas and oil prices, operating costs and production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved, probable and possible reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value.

For the year ended December 31, 2019, the Company recognized non-cash proved property impairment expense of $117.8 million due to reserve revisions which resulted from the negative impact of performance and price related revisions to the present value of our year-end proved reserves, and the relationship of that value to the historical carrying cost of our assets on the balance sheet. Included in the impairment charge was $34.5 million related to the

Company’s proved offshore Gulf of Mexico properties, primarily a result of performance revisions associated with the re-evaluation of the projected field costs and recoverable condensate volumes. In addition, the Company recognized onshore proved property impairment expense of $83.3 million, including $73.7 million in the Bullseye area in its West Texas region and $9.6 million in its Other Onshore region. The onshore impairment was primarily due to performance revisions and changes in realizable prices on the producing properties, which led to the re-evaluation of the economics and future drilling plans for the proved undeveloped locations in these areas in the current commodity price environment, which then resulted in the elimination of certain proved undeveloped locations due to the SEC’s five year development rule for such locations.

For the year ended December 31, 2018, the Company recorded an impairment expense of approximately $101.9 million related to proved properties. Included in the 2018 proved property impairment expense was $61.7 million related to the impairment of the carrying costs of the Company’s offshore Gulf of Mexico properties made during the quarter ended September 30, 2018. This impairment was primarily a result of revised proved reserve estimates based on new bottom hole pressure data gathered during the planned installation of a second stage of compression in the Company’s Eugene Island 11 field. In 2018, the Company also recognized onshore proved property impairment expense of $40.2 million, of which $24.9 million was related to certain of its non-core properties in South and Southeast Texas that were reduced to their fair value as a result of planned sales during the quarters ended September 30, 2018 and December 31, 2018, and $15.3 million of impairment was due to price related reserve revisions primarily on the Company’s Wyoming and certain South Texas assets. See Note 4 – “Acquisitions and Dispositions” for further information regarding the property dispositions.

Unproved properties are reviewed quarterly to determine if there has been an impairment of the carrying value, with any such impairment charged to expense in the period. During the year ended December 31, 2019, the Company recognized impairment expense of approximately $9.2 million related primarily to lease expirations, and near-term expirations, in the Bullseye area of the Company’s West Texas region. During the year ended December 31, 2018, the Company recognized impairment expense of approximately $1.3 million related to unproved properties due to expiring leases in its Other Onshore properties.

Asset Retirement Obligations

Asset Retirement and Environmental Obligations (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records an asset retirement obligation (“ARO”) to reflect the Company's legal obligation related to future plugging and abandonment of its oil and natural gas wells, platforms and associated pipelines and equipment. The Company estimates the expected cash flows associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should these indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells, platforms, and associated pipelines and equipment as these obligations are incurred. The liability is accreted to its present value each period, and the capitalized cost is depleted over the useful life of the related asset. The accretion expense is included in depreciation, depletion and amortization expense.

The estimated liability is based on historical experience in plugging and abandoning wells. The estimated remaining lives of the wells is based on reserve life estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate, changes in the remaining lives of the wells or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, the Company recognizes a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs. This gain or loss on abandonment is included in impairment and abandonment of oil and gas properties expense. See Note 12 - "Asset Retirement Obligation" for additional information.

Income Taxes

The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (ii) operating loss and tax credit carryforwards for tax purposes. Deferred tax assets are reduced by a valuation allowance when, based upon management’s estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. The Company reviews its tax positions quarterly for tax uncertainties. The Company did not have significant uncertain tax positions as of December 31, 2019. As described in Note 16 – “Income Taxes” with respect to Section 382 Ownership Change, the amount of unrecognized tax benefits did not change materially from December 31, 2018. The amount of unrecognized tax benefits may change in the next twelve months; however, the Company does not expect the change to have a significant impact on its financial position or results of operations. The Company includes interest and penalties in interest income and general and administrative expenses, respectively, in its statement of operations.

The Company files income tax returns in the United States and various state jurisdictions. The Company’s federal tax returns for 2009 – 2019, and state tax returns for 2009 – 2019, remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed.

Concentration of Credit Risk

Substantially all of the Company’s accounts receivable result from natural gas and oil sales or joint interest billings to a limited number of third parties in the natural gas and oil industry. This concentration of customers and joint interest owners may impact the Company’s overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. See Note 3 - "Concentration of Credit Risk" for additional information.

Debt Issuance Costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt. During the year ended December 31, 2019, the Company incurred debt issuance costs of $0.4 million related to its previous credit facility agreement with the Royal Bank of Canada (the “Credit Facility”), which matured on October 1, 2019. On September 17, 2019, the Company entered into the new revolving Credit Agreement with JPMorgan Chase Bank, N.A. and other lenders and incurred $1.8 million of debt issuance costs, which are to be amortized over the five year term of the credit line. On November 1, 2019, the Credit Agreement was amended to add two additional lenders and increase the borrowing base thereunder, and thus incurred an additional $1.6 million of debt issuance costs, which will be amortized over the remaining five year term. During the three months ended December 31, 2019, the Company expensed debt issuance costs of $0.1 million related to its Credit Agreement.

As of December 31, 2019, the remaining balance of these debt issuance costs was $3.3 million, which will be amortized through September 17, 2024, with amortization expense included in the interest expense line item in the Company's consolidated statement of operations for the year ended December 31, 2019 and the depreciation, depletion and amortization expense line item in the Company's consolidated statement of operations for the year ended December 31, 2018.

Stock-Based Compensation

The Company applies the fair value based method to account for stock based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the requisite service period, which generally aligns with the award vesting period. The Company classifies the benefits of tax deductions in excess of the compensation cost recognized for the options (excess tax benefit) as financing cash flows. The fair value of each restricted stock award is estimated as of the date of grant. The fair value of the performance stock units is estimated as of the date of grant using the Monte Carlo simulation pricing model.

Inventory

Inventory consists primarily of casing and tubing stored temporarily, which will be used for drilling or completion of wells. Inventory is recorded at the lower of cost or market using specific identification method.

Derivative Instruments and Hedging Activities

The Company accounts for its derivative activities under the provisions of ASC 815, Derivatives and Hedging (ASC 815). ASC 815 establishes accounting and reporting requirements that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, the Company hedges a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction using variable to fixed swaps and collars. The Company elected to not designate any of its derivative positions for hedge accounting. Accordingly, the net change in the mark-to-market valuation of these positions as well as all payments and receipts on settled derivative contracts are recognized in "Gain (loss) on derivatives, net" on the consolidated statements of operations for the years ended December 31, 2019 and 2018. Derivative instruments with settlement dates within one year are included in current assets or liabilities, whereas derivative instruments with settlement dates exceeding one year are included in non-current assets or liabilities. The Company calculates a net asset or liability for current and non-current derivative instruments for each counterparty based on the settlement dates within the respective contracts. See Note 6 - "Derivative Instruments" for additional information.

Subsidiary Guarantees

Contango Oil & Gas Company, as the parent company (the “Parent Company”), filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Parent Company may issue from time to time. Crimson Exploration Inc., Crimson Exploration Operating, Inc., Contango Energy Company, Contango Operators, Inc., Contango Mining Company, Conterra Company, Contaro Company, Contango Alta Investments, Inc., Contango Venture Capital Corporation, Contango Rocky Mountain Inc. and any other of the Company’s future subsidiaries specified in the prospectus supplement (each a “Subsidiary Guarantor”) are Co-Registrants with the Parent Company under the registration statement, and the registration statement also registered guarantees of debt securities by the Subsidiary Guarantors. The Subsidiary Guarantors are wholly-owned by the Parent Company, either directly or indirectly, and any guarantee by the Subsidiary Guarantors will be full and unconditional. The Parent Company has no assets or operations independent of the Subsidiary Guarantors, and there are no significant restrictions upon the ability of the Subsidiary Guarantors to distribute funds to the Parent Company. The Parent Company has one other wholly-owned subsidiary that is inactive. Finally, the Parent Company’s wholly-owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by such subsidiary without the consent of a third party.

Leases

Adoption of ASC 842

As of January 1, 2019, the Company adopted Accounting Standards Codification Topic 842 – Leases (“ASC 842”), which requires lessees to recognize a lease liability, which is a lessee’s obligation to make lease payments arising from a lease, measured on a discounted basis; and a right-of-use asset, which is an asset that represents the lessee’s right to use, or control the use of, a specified asset for the lease term on the Company’s consolidated balance sheet. Expanded disclosures with additional qualitative and quantitative information are also required.

ASC 842 contains several optional practical expedients upon adoption, one of which is referred to as the “package of three practical expedients.” The expedients must be taken together and allow entities to: (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. The Company elected to apply this practical expedient package to all of its leases upon adoption. The Company has chosen to implement the “short-term accounting policy election” which allows the Company to not include leases with an initial term of twelve months or less on the balance sheet. The Company recognizes payments on these leases within “Operating expenses” on its consolidated statement of operations. ASC 842 provides for a modified retrospective transition approach requiring lessees to recognize and measure leases on the balance sheet at the beginning of either the earliest period presented or as of the beginning of the period of adoption. The Company elected to apply ASC 842 as of the beginning of the period of adoption (January 1, 2019) and will not restate comparative periods. The Company has elected to combine and account for lease and non-lease contract components as a lease. The Company has modified procedures to its existing internal controls to review any new contracts which contain a physical asset on a quarterly basis and determine if an arrangement is, or contains, a lease at inception. The Company will continue to review all new or modified contracts on a quarterly basis for proper treatment. See Note 9 - "Leases" for additional information.

Recent Accounting Pronouncements

In November 2019, the FASB issued ASU 2019-12 – Income Taxes ("Topic 740"). The amendments in ASU 2019-12 are part of an initiative to reduce complexity in accounting standards and simplify the accounting for income taxes by removing certain exceptions from Topic 740. The amendments in this update are effective for public entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2020. The provisions of this update are not expected to have a material impact on the Company's financial position or results of operations.

In August 2018, the FASB issued ASU 2018-13 – Fair Value Measurement ("Topic 820"). The amendments in ASU 2018-13 modify the disclosure requirements on fair value measurements in Topic 820. The amendments in this update are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The provisions of this update are not expected to have a material impact on the Company's financial position or results of operations.

3. Concentration of Credit Risk

The customer base for the Company is concentrated in the natural gas and oil industry. The largest purchaser of the Company's production for the year ended December 31, 2019 was ConocoPhillips Company (36.4%). As a result of the White Star acquisition, additional purchasers that will acquire a meaningful percentage of the Company's production in the future are Enlink Midstream Operating, LP (11.6% of combined December 2019 production), Mustang Gas Products, LLC and Valero Marketing and Supply Company. The Company's sales to these companies are not secured with letters of credit and in the event of non-payment, the Company could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on the Company's financial position. There are numerous other potential purchasers of the Company's production.

4. Acquisitions and Dispositions

Juneau Joint Development Agreement

On December 23, 2019, the Company entered into a Joint Development Agreement with Juneau for aggregate consideration of $6.0 million, consisting of $1.69 million in cash and 1,725,000 shares of common stock of the Company. This agreement provides the Company the right to acquire an interest in up to six of Juneau's exploratory prospects located in the Gulf of Mexico. The first such exploratory prospect acquired by the Company is the Iron Flea prospect located in the Grand Isle Block 45 Area in the shallow waters off of the Louisiana coastline. Management considers this exploratory prospect to be an excellent complement to its PDP oriented acquisition strategy and believes it could provide a very compelling economic value proposition, even in the current low oil price environment. The Company anticipates spudding this prospect in the second quarter of 2020, and if successful, expect that the well could be producing in early 2021.

White Star Acquisition

On September 30, 2019, the Company entered into an asset purchase and sale agreement with White Star to acquire certain assets and liabilities, including approximately 306,000 net acres located in the STACK, Anadarko and Cherokee operating districts in Oklahoma. The closing of the White Star acquisition occurred on November 1, 2019, for a total aggregate consideration of $132.5 million. Following adjustments for the results of operations for the period between the effective and closing dates, and other estimated, customary closing adjustments, the net consideration paid was approximately $95.9 million in cash.

The White Star acquisition was accounted for as a business combination. Therefore, the purchase price was allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by a third-party specialist in determining the fair value of the oil and gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for the timing and amount of future development and operating costs, future plugging and abandonment costs, and a risk adjusted discount rate. The Company expects to complete the purchase price allocation during the twelve month period following the acquisition date. The following table sets forth the Company's preliminary allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

		Preliminary Purchase Price Allocation (in thousands)
Consideration:		
Cash	$	95,927
Total consideration	$	95,927
Liabilities Assumed:		
Accounts payable	$	6,323
Revenue and royalties payable		10,719
Suspended revenue and royalties		21,964
Lease liabilities		3,614
Total liabilities assumed	$	42,620
Assets acquired:		
Accounts receivable	$	18,062
Other current assets		375
Proved oil and natural gas properties		113,150
Unevaluated properties		3,041
Right-of-use lease assets		3,614
Other assets		305
Total assets acquired	$	138,547

Approximately $21.4 million of revenues and $16.3 million of direct operating expenses attributed to the White Star acquisition are included in the Company's consolidated statements of operations for the period from the closing date on November 1, 2019 through December 31, 2019.

The following unaudited pro forma combined condensed financial data for the years ended December 31, 2019 and 2018 was derived from the historical financial statements of the Company after giving effect to the White Star acquisition, as if it had occurred on January 1, 2018. The below information reflects pro forma adjustments for the private placement of the Company's Series B contingent convertible preferred stock and an increase in borrowings under the Company's Credit Agreement, the proceeds of which were used to pay the purchase price of the White Star acquisition, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including the depletion of the fair-valued proved oil and natural gas properties acquired from White Star and the exclusion of acquisition-related costs incurred by the Company of approximately $1.9 million for the year ended December 31, 2019. The pro forma results of operations do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate the assets acquired. In addition, the results of operations for both years include non-cash impairment expense for White Star based on historical costs and not the fair value of the oil and gas properties acquired as reflected in the allocation of the purchase price. The pro forma financial data does not include the pro forma results of operations for any other acquisitions made during the periods presented, as they were not deemed material. The pro forma consolidated statements of operations data has been included for comparative purposes only, is not necessarily indicative of the results that might have occurred had the acquisition taken place on January 1, 2018 and is not intended to be a projection of future results.

(In thousands except for per share amounts)	Year Ended December 31, 2019		2018	
Revenues	$	207,530	$	315,362
Net Income	$	(265,760)	$	(545,048)
Basic Earnings per share	$	(4.20)	$	(14.74)
Diluted earnings per share	$	(4.20)	$	(14.74)

Will Energy Acquisition

On September 12, 2019, the Company announced it entered into a contribution and purchase agreement with Will Energy to acquire approximately 155,900 net acres located in North Louisiana (8,000 net acres) and the Western Anadarko Basin in Western Oklahoma and the Texas Panhandle (147,900 net acres). Closing of the Will Energy acquisition occurred on October 25, 2019, for a total aggregate consideration of $23 million. Following adjustments for recent sales of non-core, non-operated Louisiana properties by Will Energy, the results of operations for the period between the effective and closing dates, and other estimated, customary closing adjustments, the net consideration paid consisted of $14.75 million in cash and 3.5 million shares of common stock.

Southern Delaware Basin Acquisition

In December 2018, the Company purchased an additional 4,200 gross operated (1,700 net) acres and 4,000 gross non-operated (200 net) acres to the northeast of its existing West Texas acreage ("NE Bullseye") for approximately $7.5 million. The Company paid $3.2 million cash in December 2018, with the remaining balance paid in installments in March and October of 2019.

Frio and Zavala County Property Sale

On July 1, 2019, the Company sold certain minor, non-core operated assets located in Frio and Zavala counties, Texas in exchange for the buyer's assumption of the plugging and abandonment liabilities of the properties. The Company recorded a gain of $0.2 million after removal of the asset retirement obligations associated with the sold properties.

Lavaca and Wharton County Property Sale

On June 10, 2019, the Company sold certain minor, non-core operated assets located in Lavaca and Wharton counties, Texas in exchange for the buyer's assumption of the plugging and abandonment liabilities of the properties. The Company recorded a gain of $0.4 million after removal of the asset retirement obligations associated with the sold properties.

Brooks and Zapata County Property Sale

Effective December 31, 2018, the Company sold its assets located primarily in Brooks and Zapata counties in South Texas for a cash purchase price of $150,000. As a result of this planned sale, the Company reduced the value of the assets to their fair value and recorded an impairment of approximately $12.1 million included in "Impairment and abandonment of oil and gas properties" in the Company's consolidated statement of operations.

Elm Hill Property Sale

On December 4, 2018, the Company sold its non-core assets located in Fayette, Gonzales, Caldwell and Bastrop counties in South Texas for a cash purchase price of $85,000. The Company recorded a gain of approximately $175,000 after removal of the asset retirement obligations associated with the sold properties.

Vermilion 170 Property Sale

Effective December 1, 2018, the Company sold its offshore Vermilion 170 well in exchange for a continuing ORRI in the Vermilion 170 well, the buyer's assumption of the plugging and abandonment liability for the well, platform and associated pipeline and an ORRI in any future wells drilled by the buyer on two nearby prospects that would produce through this platform.

Liberty and Hardin County Property Sale

On September 11, 2018, the Company entered into a definitive agreement to divest certain of its non-core assets in Liberty and Hardin counties in Southeast Texas. As a result of the sale, the Company reduced the value of the assets to their purchase price and recorded an impairment of approximately $12.8 million during the three months ended September 30, 2018 in "Impairment and abandonment of oil and gas properties" in the Company's consolidated statement of operations. The sale was completed on November 2, 2018 for cash proceeds of $6.0 million.

Starr County Property Sale

On May 25, 2018, the Company sold its non-operated assets located in Starr County, Texas for a cash purchase price of $0.6 million. The Company recorded a gain of $1.3 million after removal of the asset retirement obligations associated with the sold properties.

Karnes County Property Sale

On March 28, 2018, the Company sold its operated Eagle Ford Shale assets located in Karnes County, Texas for a cash purchase price of $21.0 million. The Company recorded a net gain of $9.5 million.

5. Fair Value Measurements

Pursuant to ASC 820, Fair Value Measurements and Disclosures (ASC 820), the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ASC 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy assigns the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 measurements are inputs that are observable for assets or liabilities, either directly or indirectly, other than quoted prices included within Level 1. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

As required by ASC 820, a financial instrument's level within the fair value hierarchy is 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 fair value assets and liabilities and their placement within the fair value hierarchy levels. There have been no transfers between Level 1, Level 2 or Level 3.

Derivatives are recorded at fair value at the end of each reporting period. The Company records the net change in the fair value of these positions in "Gain (loss) on derivatives, net" in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curves for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves. See Note 6 - "Derivative Instruments" for additional discussion of derivatives.

During the year ended December 31, 2019, the Company's derivative contracts were with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. As such, the Company was exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company did not anticipate any nonperformance. The Company did not post collateral under any of these contracts as they are secured under the Credit Agreement or under unsecured lines of credit with non-bank counterparties.

Estimates of the fair value of financial instruments are made in accordance with the requirements of ASC 825, Financial Instruments. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company's Credit Agreement approximates carrying value because the interest rate approximates current market rates and are re-set at least every three months. See Note 13 - "Long-Term Debt" for further information.

Fair value estimates used for non-financial assets are evaluated at fair value on a non-recurring basis and include oil and gas properties evaluated for impairment when facts and circumstances indicate that there may be an impairment. If the unamortized cost of properties exceeds the undiscounted cash flows related to the properties, the value of the properties is compared to the fair value estimated as discounted cash flows related to the risk-adjusted proved, probable and possible reserves related to the properties. Fair value measurements based on these inputs are classified as Level 3.

Impairments

Contango tests proved oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. The Company estimates the undiscounted future cash flows expected in connection with the oil and gas properties on a field by field basis and compares such future cash flows to the unamortized capitalized costs of the properties. If the estimated future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to its fair value. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Additionally, the Company may use appropriate market data to determine fair value. Because these significant fair value inputs are typically not observable, impairments of long-lived assets are classified as a Level 3 fair value measure.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period.

Asset Retirement Obligations

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. The factors used to determine fair value include, but are not limited to, estimated future plugging and abandonment costs and expected lives of the related reserves. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3 at inception.

6. Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk. Derivative contracts are utilized to hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil and natural gas production. The Company typically hedges a substantial, but varying, portion of anticipated oil and natural gas production for future periods. The Company believes that these derivative arrangements, although not free of risk, allow it to achieve a more predictable cash flow and to reduce exposure to commodity price fluctuations. However, derivative arrangements limit the benefit of increases in the prices of oil, natural gas and natural gas liquids sales. Moreover, because its derivative arrangements apply only to a portion of its production, the Company’s strategy provides only partial protection against declines in commodity prices. Such arrangements may expose the Company to risk of financial loss in certain circumstances. The Company continuously reevaluates its hedging programs in light of changes in production, market conditions and commodity price forecasts.

As of December 31, 2019, the Company’s natural gas and oil derivative positions consisted of “swaps” and “costless collars”. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for oil and natural gas. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract, and a purchased put, which establishes a minimum price. A sold put option limits the exposure of the counterparty's risk should the price fall below the strike price. Sold put options limit the effectiveness of purchased put options at the low end of the put/call collars to market prices in excess of the strike price of the put option sold.

It is the Company's practice to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. The Company did not post collateral under any of these contracts as they are secured under the Credit Agreement or under unsecured lines of credit with non-bank counterparties.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, derivatives are carried at fair value on the consolidated balance sheets as assets or liabilities, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs. The Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in "Gain (loss) on derivatives, net" on the consolidated statements of operations. See Note 5 – “Fair Value Measurements” for additional information.

The company currently has hedges in place for 70% and 67% of its currently forecasted PDP oil production for 2020 and 2021, respectively, at average floor prices of $55.13 and $51.71 per barrel, respectively. For natural gas, the Company has 68% and 57% of currently forecasted PDP production for 2020 and 2021, respectively, hedged at average floor prices of $2.57 and $2.49 per mmbtu, and 76% of forecasted PDP production for the first quarter of 2022 hedged with swaps at $2.54 per mmbtu. Approximately 98% of the Company’s hedges are swaps, and the Company has no three way collars or short puts.

The Company had the following financial derivative contracts in place as of December 31, 2019:

Commodity	Period	Derivative	Volume/Month		Price/Unit		Fair Value
Natural Gas	Jan 2020 - March 2020	Swap	425,000	Mmbtus	$ 2.841	(1)	$ 856
Natural Gas	Jan 2020 - March 2020	Collar	225,000	Mmbtus	$ 2.45 - 3.40	(1)	209
Natural Gas	April 2020 - July 2020	Swap	400,000	Mmbtus	$ 2.532	(1)	493
Natural Gas	Aug 2020 - Oct 2020	Swap	40,000	Mmbtus	$ 2.532	(1)	25
Natural Gas	Nov 2020 - Dec 2020	Swap	375,000	Mmbtus	$ 2.696	(1)	134
Natural Gas	Jan 2020 - March 2020	Swap	300,000	Mmbtus	$ 2.53	(1)	325
Natural Gas	April 2020 - July 2020	Swap	400,000	Mmbtus	$ 2.53	(1)	490
Natural Gas	Aug 2020 - Dec 2020	Swap	350,000	Mmbtus	$ 2.53	(1)	223
Natural Gas	Jan 2020 - March 2020	Swap	300,000	Mmbtus	$ 2.532	(1)	327
Natural Gas	April 2020 - July 2020	Swap	400,000	Mmbtus	$ 2.532	(1)	493
Natural Gas	Aug 2020 - Dec 2020	Swap	350,000	Mmbtus	$ 2.532	(1)	226
Oil	Jan 2020 - June 2020	Swap	22,000	Bbls	$ 57.74	(2)	(289)
Oil	July 2020 - Dec 2020	Swap	15,000	Bbls	$ 57.74	(2)	68
Oil	Jan 2020 - March 2020	Swap	2,700	Bbls	$ 54.33	(2)	(51)
Oil	April 2020 - June 2020	Swap	2,500	Bbls	$ 54.33	(2)	(37)
Oil	July 2020	Swap	5,500	Bbls	$ 54.33	(2)	(21)
Oil	Aug 2020 - Oct 2020	Swap	2,500	Bbls	$ 54.33	(2)	(21)
Oil	Nov 2020 - Dec 2020	Swap	3,500	Bbls	$ 54.33	(2)	(12)
Oil	Jan 2020 - Feb 2020	Swap	42,500	Bbls	$ 54.70	(2)	(517)
Oil	March 2020 - July 2020	Swap	37,500	Bbls	$ 54.70	(2)	(842)
Oil	Aug 2020 - Dec 2020	Swap	35,000	Bbls	$ 54.70	(2)	(354)
Oil	Jan 2020 - Feb 2020	Swap	42,500	Bbls	$ 54.58	(2)	(527)
Oil	March 2020 - July 2020	Swap	37,500	Bbls	$ 54.58	(2)	(864)
Oil	Aug 2020 - Dec 2020	Swap	35,000	Bbls	$ 54.58	(2)	(373)
Oil	Jan 2020 - Oct 2020	Collar	3,442	Bbls	$ 52.00 - 65.70	(2)	18
Natural Gas	Jan 2021 - March 2021	Swap	185,000	Mmbtus	$ 2.505	(1)	(78)
Natural Gas	April 2021 - July 2021	Swap	120,000	Mmbtus	$ 2.505	(1)	99
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	Mmbtus	$ 2.505	(1)	4
Natural Gas	Jan 2021 - March 2021	Swap	185,000	Mmbtus	$ 2.508	(1)	(75)
Natural Gas	April 2021 - July 2021	Swap	120,000	Mmbtus	$ 2.508	(1)	104
Natural Gas	Aug 2021 - Sept 2021	Swap	10,000	Mmbtus	$ 2.508	(1)	4

Natural Gas	Jan 2021 - March 2021	Swap	650,000	Mmbtus	$ 2.508	(1)	(268)
Natural Gas	April 2021 - Oct 2021	Swap	400,000	Mmbtus	$ 2.508	(1)	544
Natural Gas	Nov 2021 - Dec 2021	Swap	580,000	Mmbtus	$ 2.508	(1)	20
Oil	Jan 2021 - March 2021	Swap	19,000	Bbls	$ 50.00	(2)	(291)
Oil	April 2021 - July 2021	Swap	12,000	Bbls	$ 50.00	(2)	(196)
Oil	Aug 2021 - Sept 2021	Swap	10,000	Bbls	$ 50.00	(2)	(67)
Oil	Jan 2021 - July 2021	Swap	62,000	Bbls	$ 52.00	(2)	(1,122)
Oil	Aug 2021 - Sept 2021	Swap	55,000	Bbls	$ 52.00	(2)	(157)
Oil	Oct 2021 - Dec 2021	Swap	64,000	Bbls	$ 52.00	(2)	(184)
			Total net fair value of derivative instruments (in thousands)				$ (1,684)

(1) Based on Henry Hub NYMEX natural gas prices.

(2) Based on West Texas Intermediate oil prices.

In addition to the above financial derivative instruments, the Company also had a costless swap agreement with a Midland WTI – Cushing oil differential swap price of $0.05 per barrel of oil. The agreement fixes the Company's exposure to that differential on 12,000 barrels of oil per month for January 2020 through June 2020 and 10,000 barrels per month for July 2020 through December 2020. The fair value of this costless swap agreement was in a liability position of $0.1 million as of December 31, 2019.

The Company had the following financial derivative contracts in place as of December 31, 2018:

Commodity	Period	Derivative	Volume/Month		Price/Unit		Fair Value
Natural Gas	Jan 2019 - March 2019	Swap	600,000	MMBtus	$ 3.21	(1)	$ 121
Natural Gas	April 2019 - July 2019	Swap	600,000	MMBtus	$ 2.75	(1)	109
Natural Gas	Aug 2019 - Oct 2019	Swap	100,000	MMBtus	$ 2.75	(1)	3
Natural Gas	Nov 2019 - Dec 2019	Swap	500,000	MMBtus	$ 2.75	(1)	(116)
Oil	Jan 2019 - Dec 2019	Collar	7,000	Bbls	$ 50.00 - 58.00	(2)	(27)
Oil	Jan 2019 - Dec 2019	Collar	4,000	Bbls	$ 52.00 - 59.45	(3)	233
Oil	Jan 2019 - June 2019	Collar	12,000	Bbls	$ 70.00 - 76.25	(3)	1,569
Oil	Jan 2019 - July 2019	Swap	6,000	Bbls	$ 66.10	(3)	811
Oil	July 2019	Swap	12,000	Bbls	$ 72.10	(3)	288
Oil	Aug 2019 - Oct 2019	Swap	9,000	Bbls	$ 72.10	(3)	635
Oil	Nov 2019 - Dec 2019	Swap	12,000	Bbls	$ 72.10	(3)	552
			Total net fair value of derivative instruments (in thousands)				$ 4,178

(1) Based on Henry Hub NYMEX natural gas prices.

(2) Based on Argus Louisiana Light Sweet oil prices.

(3) Based on West Texas Intermediate oil prices.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2019 (in thousands).

	Gross	Netting (1)	Total
Assets	$ 4,176	$ —	$ 4,176
Liabilities	$ (5,971)	$ —	$ (5,971)

(1) Represents counterparty netting under agreements governing such derivatives.

Derivatives listed above are recorded in "Current derivative asset or liability" and "Long-term derivative asset or liability" on the Company's consolidated balance sheet and include swaps and costless collars that are carried at fair value.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2018 (in thousands):

	Gross	Netting [(1)]	Total
Assets	$ 4,600	$ —	$ 4,600
Liabilities	$ (422)	$ —	$ (422)

(1) Represents counterparty netting under agreements governing such derivatives.

Derivatives listed above are recorded in "Current derivative asset or liability" and "Long-term derivative liability" on the Company's consolidated balance sheet and include swaps and costless collars that are carried at fair value.

The following table summarizes the effect of derivative contracts on the Consolidated Statements of Operations for the years ended December 31, 2019 and 2018 (in thousands):

	Year Ended December 31,	
Contract Type	**2019**	**2018**
Oil contracts	$ 1,614	$ (2,969)
Natural gas contracts	1,002	(513)
Realized gain (loss)	$ 2,616	$ (3,482)
Oil contracts	$ (10,012)	$ 6,126
Natural gas contracts	4,039	(705)
Unrealized gain (loss)	$ (5,973)	$ 5,421
Gain (loss)on derivatives, net	$ (3,357)	$ 1,939

In March 2020, the Company entered into the following additional derivative contracts:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Natural Gas	April 2021 - Nov 2021	Swap	70,000 Mmbtus	$ 2.36 [(1)]
Natural Gas	Dec 2021	Swap	350,000 Mmbtus	$ 2.36 [(1)]
Natural Gas	Jan 2022 - March 2022	Swap	780,000 Mmbtus	$ 2.54 [(1)]

(1) Based on Henry Hub NYMEX natural gas prices.

7. Stock Based Compensation

As of December 31, 2019, the Company had in place the Contango Oil & Gas Company Second Amended and Restated 2009 Incentive Compensation Plan ("the Second Amended 2009 Plan") which allows for stock options, restricted stock or performance stock units to be awarded to officers, directors and employees as a performance-based award.

Second Amended and Restated 2009 Incentive Compensation Plan

On March 21, 2017, the Company's board of directors (the "Board") amended and restated the Company's then existing incentive compensation plan through the adoption of the Second Amended 2009 Plan. The Second Amended 2009 Plan provides for both cash awards and equity awards to officers, directors, employees or consultants of the

Company. Awards made under the Second Amended 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board.

Under the terms of the Second Amended 2009 Plan, shares of the Company's common stock may be issued for plan awards. Stock options under the Second Amended 2009 Plan must have an exercise price of each option equal to or greater than the market price of the Company's common stock on the date of grant. The Company may grant officers and employees both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended, and stock options that are not qualified as incentive stock options. Stock option grants to non-employees, such as directors and consultants, can only be stock options that are not qualified as incentive stock options. Options granted generally expire after five or ten years. The vesting schedule for all equity awards varies from immediately to over a four-year period. As of December 31, 2019, the Company had approximately 1.5 million shares of equity awards available for future grant under the Second Amended 2009 Plan, assuming performance stock units are settled at 100% of target.

Effective January 1, 2014, the Company implemented performance-based long-term bonus plans under the 2009 Plan for the benefit of all employees through a Cash Incentive Bonus Plan ("CIBP") and a Long-Term Incentive Plan ("LTIP"). The specific targeted performance measures under these sub-plans are approved by the Compensation Committee and/or the Board. Upon achieving the performance levels established each year, bonus awards under the CIBP and LTIP will be calculated as a percentage of base salary of each employee for the plan year. The CIBP and LTIP plan awards for each year are expected to be disbursed in the first quarter of the following year. Employees must be employed by the Company at the time that awards are disbursed to be eligible.

The CIBP awards will be paid in cash while LTIP awards will consist of restricted common stock, performance stock units and/or stock options. The number of shares of restricted common stock and the number of shares underlying the stock options granted will be determined based upon the fair market value of the common stock on the date of the grant.

2005 Stock Incentive Plan

The 2005 Plan was adopted by the Company's Board in conjunction with the merger with Crimson Exploration, Inc. This plan expired on February 25, 2015, and therefore, no additional shares are available for grant.

Stock Options

A summary of stock options as of and for the years ended December 31, 2019 and 2018 is presented in the table below (dollars in thousands, except per share data):

	Year Ended December 31,			
	2019		2018	
	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price
Outstanding, beginning of the period	33,637	$ 55.82	94,833	$ 57.69
Exercised	—	$ —	—	$ —
Expired / Forfeited	(12,673)	$ 51.34	(61,196)	$ 58.72
Outstanding, end of year	20,964	$ 58.53	33,637	$ 55.82
Aggregate intrinsic value	$ —		$ —	
Exercisable, end of year	20,964	$ 58.53	33,637	$ 55.82
Aggregate intrinsic value	$ —		$ —	
Available for grant, end of the period*	1,480,389		1,854,588	
Weighted average fair value of options granted during the period	$ —		$ —	

* Excludes performance stock units.

During the years ended December 31, 2019 and 2018, the Company did not issue any stock options. During the year ended December 31, 2019, 12,673 stock options previously issued were forfeited by former employees. During the year ended December 31, 2018, 61,196 stock options previously issued were forfeited by former employees, of which 55,943 were related to the resignation of the Company's former President and CEO in September 2018.

As of December 31, 2019, there were 20,964 stock options vested and exercisable under the 2005 Plan. The exercise price for such options ranges from $28.96 to $60.33 per share, with an average remaining contractual life of 1.2 years.

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the years ended December 31, 2019 and 2018, there was no excess tax benefit recognized. See Note 2 – "Summary of Significant Accounting Policies".

Compensation expense related to employee stock option grants are recognized over the stock option's vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model.

During the years ended December 31, 2019 and 2018, the Company did not recognize any stock option expense. The aggregate intrinsic value of stock options exercised/forfeited during each of the years ended December 31, 2019 and 2018 was zero.

Restricted Stock

During the year ended December 31, 2019, the Company issued 307,650 restricted stock awards to new and existing employees, which vest over three years, plus an additional 80,410 restricted stock awards to the members of the board of directors, which vest on the one-year anniversary of the date of grant, as part of their 2019 director compensation. During the year ended December 31, 2019, 91,346 restricted stock awards were forfeited by former employees. The weighted average fair value of the restricted shares granted during the year was $2.91, with a total grant date fair value of approximately $1.1 million after adjustment for estimated weighted average forfeiture rate of 0.0%.

During the year ended December 31, 2018, the Company issued 225,782 restricted stock awards from the 2009 Plan, which vest over three years, to executive officers as part of their overall 2018 compensation packages. Additionally, the Company issued 82,500 restricted stock awards from the 2009 Plan, which vest on the one-year anniversary of the date of grant, to the members of the board of directors as part of their 2018 director compensation. During the year ended December 31, 2018, 160,378 restricted stock awards were forfeited by former employees, of which 105,800 were related to the resignation of the Company's former President and CEO in September 2018. 102,573 of the shares vested in 2018 were also related to the resignation of the Company's former President and CEO in September 2018. The weighted average fair value of the restricted shares granted during the year was $3.76, with a total grant date fair value of approximately $1.2 million after adjustment for estimated weighted average forfeiture rate of 0.0%.

Restricted stock activity as of December 31, 2019 and 2018 and for the years then ended is presented in the table below (dollars in thousands, except per share data):

	2019			2018		
	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value
Outstanding, beginning of the period	459,621	$ 7.26	$ 662	731,073	$ 10.55	$ 1,667
Granted	388,060	2.91	—	308,282	3.76	98
Vested	(353,114)	7.41	1,171	(419,356)	10.72	1,965
Canceled / Forfeited	(91,346)	4.08	41	(160,378)	6.49	309
Not vested, end of the period	403,221	3.66	214	459,621	7.26	662

The Company recognized approximately $1.9 million and $3.8 million in restricted stock compensation expense during the years ended December 31, 2019 and 2018, respectively, for restricted shares granted to its officers, employees and directors. The higher 2018 expense is primarily related to the resignation of the Company's former President and CEO in September 2018 and the immediate vesting of his restricted shares of common stock. As of December 31, 2019, there were 403,221 shares of unvested restricted stock outstanding. An additional $0.8 million of compensation expense will be recognized over the remaining vesting period.

Performance Stock Units

Performance stock units ("PSUs") represent a contractual right to receive shares of the Company's common stock. The settlement of PSUs may range from 0% to 300% of the targeted number of PSUs stated in the agreement contingent upon the achievement of certain share price appreciation targets as compared to a peer group index. The PSUs vest and settlement is determined after a three year period.

Compensation expense associated with PSUs is based on the grant date fair value of a single PSU as determined using the Monte Carlo simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the PSUs with shares of the Company's common stock after three years, the PSU awards are accounted for as equity awards, and the fair value is calculated on the grant date. The simulation model calculates the payout percentage based on the stock price performance over the performance period. The concluded fair value is based on the average achievement percentage over all the iterations. The resulting fair value expense is amortized over the life of the PSU award.

During the year ended December 31, 2019, the Company granted 117,105 PSUs to executive officers and employees as part of their overall compensation package, which will be measured between January 1, 2019 and December 31, 2021, and were valued at a weighted average fair value of $6.42 per unit. All fair value prices were determined using the Monte Carlo simulation model. During the year ended December 31, 2019, 71,945 PSUs were forfeited by former employees, including 49,773 PSU forfeitures due to the resignations of the Company's former Senior Vice President of Exploration and Senior Vice President of Operations and Engineering in February 2019. The Company only recognized approximately $0.5 million in stock compensation expense related to PSUs during 2019, primarily due to the expiration of PSUs which failed to meet their target as of December 31, 2018 and the above referenced forfeitures. As of December 31, 2019, an additional $0.8 million of compensation expense related to PSUs remained to be recognized over the remaining weighted-average vesting period of 1.8 years. In January 2020, 77,485 of the 2017 PSU grants vested.

During the year ended December 31, 2018, the Company granted 190,782 PSUs to executive officers, as part of their overall compensation package, at a weighted average fair value of $7.69 per unit. All prices were determined using the Monte Carlo simulation model. Also during 2018, 188,927 PSUs were forfeited by former employees, of which 153,127 were related to the resignation of the Company's former President and CEO in September 2018. The Company recognized approximately $1.0 million in stock compensation expense related to PSUs during 2018.

8. Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program. All shares are to be purchased in the open market or through privately negotiated transactions. Purchases are made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market, and when the Company believes its stock price to be undervalued. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes. No shares were purchased during the years ended December 31, 2019 and 2018. As of December 31, 2019, the Company had $31.8 million available under the share repurchase program for future purchases; however, repurchases could be limited by provisions of the Company's Credit Agreement.

9. Leases

As of January 1, 2019, the Company adopted Accounting Standards Codification Topic 842 – Leases ("ASC 842"), which requires lessees to recognize a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis, and a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term on the Company's consolidated balance sheet. Expanded disclosures with additional qualitative and quantitative information are also required.

ASC 842 contains several optional practical expedients upon adoption, one of which is referred to as the "package of three practical expedients." The expedients must be taken together and allow entities to: (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. The Company elected to apply this practical expedient package to all of its leases upon adoption. The Company also chose to implement the "short-term accounting policy election" which allows the Company to not include leases with an initial term of twelve months or less on the balance sheet. The Company recognizes payments on these leases within "Operating expenses" on its consolidated statement of operations. ASC 842 provides for a modified retrospective transition approach requiring lessees to recognize and measure leases on the balance sheet at the beginning of either the earliest period presented or as of the beginning of the period of adoption. The Company elected to apply ASC 842 as of the beginning of the period of adoption (January 1, 2019) and will not restate comparative periods. For new leases, the Company determines if an arrangement is, or contains, a lease at inception. The Company has elected to combine and account for lease and non-lease contract components as a lease.

As of January 1, 2019, the majority of the Company's operating leases were for field equipment, such as compressors. The adoption of ASC 842 did not have a material effect on the Company's financial results or disclosures. Leases which are on a month-to-month basis and can be easily substituted or cancelled by either party with minimal penalties are considered "short-term". Short term leases are not included on the Company's balance sheet and are recognized on the statement of operations on a straight-line basis over the lease term. During the year ended December 31, 2019, the Company entered into new office lease agreements and compressor contracts with lease terms of twelve months or more, which qualify as operating leases under the new standard. The Company's corporate offices are located in Houston, Texas, under a lease that expires March 31, 2021 and Oklahoma City, Oklahoma, under a lease that expires January 31, 2022. The Company's three field offices are located in Oklahoma, under leases which will begin to expire in 2021.

During the year ended December 31, 2019, the Company also entered into new vehicle leases and office equipment contracts, which qualify as finance leases. These leases do not have a material net impact on the Company's consolidated financial statements.

The following table summarizes the balance sheet information related to the Company's leases as of December 31, 2019 (in thousands):

		December 31, 2019
Operating lease right of use asset [(1)]	$	4,316
Operating lease liability - current [(2)]	$	(2,597)
Operating lease liability - long-term [(3)]		(1,738)
Total operating lease liability	$	(4,335)
Financing lease right of use asset [(1)]	$	1,569
Financing lease liability - current [(2)]	$	(524)
Financing lease liability - long-term [(3)]		(1,051)
Total financing lease liability	$	(1,575)

(1) Included in "Right-of-use lease assets" on the consolidated balance sheet.
(2) Included in "Accounts payable and accrued liabilities" on the consolidated balance sheet.
(3) Included in "Lease liabilities" on the consolidated balance sheet.

The Company's leases generally do not provide an implicit rate, and therefore the Company uses its incremental borrowing rate as the discount rate when measuring operating lease liabilities. The incremental borrowing rate represents an estimate of the interest rate the Company would incur at lease commencement to borrow an amount equal to the lease payments on a collateralized basis over the term of a lease within a particular currency environment. For operating leases existing prior to January 1, 2019, the incremental borrowing rate as of January 1, 2019 was used for the remaining lease term.

The table below presents the weighted average remaining lease terms and weighted average discount rates for the Company's leases as of December 31, 2019:

	December 31, 2019
Weighted Average Remaining Lease Terms (in years):	
Operating leases	2.16
Financing leases	3.14
Weighted Average Discount Rate:	

Operating leases	6.04%
Financing leases	6.24%

Maturities for the Company's lease liabilities on the consolidated balance sheet as of December 31, 2019, were as follows (in thousands):

	December 31, 2019	
	Operating Leases	**Financing Leases**
2020	$ 2,786	$ 583
2021	1,318	544
2022	197	322
2023	170	186
2024	157	11
2025	-	-
Total future minimum lease payments	4,628	1,646
Less: imputed interest	(293)	(71)
Present value of lease liabilities	$ 4,335	$ 1,575

The following table summarizes expenses related to the Company's leases for the three and twelve months ended December 31, 2019 (in thousands):

	Three Months Ended December 31, 2019	**Year Ended December 31, 2019**
Operating lease cost (1) (2)	$ 542	$ 742
Financing lease cost - amortization of right-of-use assets	87	92
Financing lease cost - interest on lease liabilities	17	18
Administrative lease cost (3)	19	75
Short-term lease cost (1) (4)	741	4,101
Total lease cost	$ 1,406	$ 5,028

(1) This total does not reflect amounts that may be reimbursed by other third parties in the normal course of business, such as non-operating working interest owners.
(2) Costs related to office leases and compressors with lease terms of twelve months of more.
(3) Costs related primarily to office equipment and IT solutions with lease terms of more than one month and less than one year.
(4) Costs related primarily to drilling rigs, generators and compressor agreements with lease terms of more than one month and less than one year.

There were $0.8 million and $0.1 million in cash payments related to operating leases and financing leases, respectively, during the twelve months ended December 31, 2019.

10. Other Financial Information

The following table provides additional detail for accounts receivable, prepaids, and accounts payable and accrued liabilities which are presented on the consolidated balance sheets (in thousands):

	December 31, 2019	December 31, 2018
Accounts receivable:		
Trade receivables	$ 21,110	$ 6,052
Receivable for Alta Resources distribution	1,712	1,993
Joint interest billings	13,104	3,833
Income taxes receivable	509	424
Other receivables	4,126	223
Allowance for doubtful accounts	(994)	(994)
Total accounts receivable	$ 39,567	$ 11,531
Prepaid expenses and other:		
Prepaid insurance	$ 683	$ 792
Other	508	511
Total prepaid expenses and other	$ 1,191	$ 1,303
Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 49,644	$ 17,986
Advances from partners	6,733	1,785
Accrued exploration and development	8,210	4,751
Accrued acquisition costs	—	4,352
Trade payables	14,086	3,385
Accrued general and administrative expenses	12,037	2,545
Accrued operating expenses	5,794	1,801
Accrued short term leases	3,120	—
Other accounts payable and accrued liabilities	4,969	2,901
Total accounts payable and accrued liabilities	$ 104,593	$ 39,506

Included in the table below is supplemental cash flow disclosures and non-cash investing activities during the years ended December 31, 2019 and 2018, in thousands:

	Year Ended December 31,	
	2019	2018
Cash payments:		
Interest payments	$ 7,761	$ 5,656
Income tax payments, net of cash refunds	668	81
Non-cash items excluded from investing activities in the consolidated statements of cash flows:		
Increase (decrease) in accrued capital expenditures	1,841	(3,649)

11. Investment in Exaro Energy III LLC

Through the Company’s wholly-owned subsidiary, Contaro Company (“Contaro”), the Company committed to invest up to $67.5 million in Exaro for an ownership interest of approximately 37%. The aggregate commitment of all the Exaro investors was approximately $183 million. The Company did not make any contributions during the year ended December 31, 2019 and has no plans to invest additional funds in Exaro, as the commitment to invest in Exaro expired on March 31, 2017. As of December 31, 2019, the Company had invested approximately $46.9 million. Contango’s share in the equity of Exaro at December 31, 2019 was approximately $6.8 million.

The Company's share in Exaro's results of operations recognized for the years ended December 31, 2019 and 2018 was a gain of $1.0 million, net of zero tax expense and a loss of $12.6 million, net of zero tax, respectively.

12. Asset Retirement Obligation

The Company accounts for its retirement obligation of long lived assets by recording the net present value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. When the liability is initially recorded, a company increases the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement.

Activities related to the Company's ARO during the years ended December 31, 2019 and 2018 were as follows (in thousands):

	Year Ended December 31,	
	2019	**2018**
Balance as of the beginning of the period	$ 13,497	$ 22,405
Liabilities incurred during period	256	163
Liabilities settled during period	(1,380)	(1,339)
Accretion	1,062	960
Sales	(816)	(8,599)
Acquisitions	37,596	—
Change in estimate	1,450	(93)
Balance as of the end of the period	$ 51,665	$ 13,497

All of the total liabilities incurred during the years ended December 31, 2019 and 2018 were related to new wells drilled during the period. All of the total liabilities settled during the years ended December 31, 2019 and 2018 were related to wells plugged and abandoned during the period. The acquisitions refer to new liabilities assumed from the properties acquired in the White Star and Will Energy acquisitions.

13. Long-Term Debt

Credit Agreement

On September 17, 2019, the Company entered into its new revolving Credit Agreement with JPMorgan Chase Bank, N.A. and other lenders, which established a borrowing base of $65 million. The Credit Agreement was amended on November 1, 2019, in conjunction with the closing of the Will Energy and White Star acquisitions, to add two additional lenders and increase the borrowing base thereunder to $145 million, which is the current borrowing base. The borrowing base is subject to semi-annual redeterminations. Beginning in 2020, the semi-annual redeterminations will occur on May 1st and November 1st of each year. The borrowing base may also be adjusted by certain events, including the incurrence of any senior unsecured debt, material asset dispositions or liquidation of hedges in excess of certain thresholds. The Credit Agreement matures on September 17, 2024.

On September 18, 2019, the Company repaid all obligations outstanding on, and terminated, its previous Credit Facility with the Royal Bank of Canada, which matured on October 1, 2019, with borrowings under the Credit Agreement.

Initially, the Company incurred $1.8 million of arrangement and upfront fees in connection with the Credit Agreement, which was to be amortized over the five year term of the Credit Agreement. On November 1, 2019, in connection with the amendment of the Credit Agreement, the Company incurred an additional $1.6 million of debt issuance costs, which will be amortized over the remaining five year term. As of December 31, 2019, the remaining balance of these fees was $3.3 million, which will be amortized through September 17, 2024.

As of December 31, 2019, the Company had $72.8 million outstanding under the Credit Agreement and $1.9 million in outstanding letters of credit. As of December 31, 2018, the Company had $60.0 million outstanding under the Credit Facility and $1.9 million in outstanding letters of credit. As of December 31, 2019, borrowing availability under the Credit Agreement was $70.3 million.

The Credit Agreement is collateralized by liens on substantially all of the Company's oil and gas properties and other assets and security interests in the stock of its wholly owned and/or controlled subsidiaries. The Company's wholly owned and/or controlled subsidiaries are also required to join as guarantors under the Credit Agreement.

Borrowings under the Credit Agreement bear interest at LIBOR, the U.S. prime rate, or the federal funds rate, plus a 1.25% to 3.25% margin, dependent upon the amount outstanding. Total interest expense under the Company's Credit Agreement and Credit Facility, and other financing fees, including commitment fees, for the years ended December 31, 2019 and 2018 was approximately $8.6 million and $5.5 million, respectively.

The weighted average interest rates in effect at December 31, 2019 and December 31, 2018 were 4.3% under the Credit Agreement and 6.3% under the Credit Facility, respectively.

The Credit Agreement contains customary and typical restrictive covenants. Commencing in the quarter ending December 31, 2019, the Credit Agreement requires a Current Ratio of greater than or equal to 1.0 and a Leverage Ratio of less than or equal to 3.50, both as defined in the Credit Agreement. The Credit Agreement also contains events of default that may accelerate repayment of any borrowings and/or termination of the facility. Events of default include, but are not limited to, a going concern qualification, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events. As of December 31, 2019, the Company was in compliance with all of its covenants under the Credit Agreement.

14. Commitments and Contingencies

Contango leases its office space, compressors, vehicles and certain other equipment, which are considered operating and finance leases. See Note 9 – "Leases" for more information. The Company also incurs commitments on its oil and gas leases, such as delay rentals, surface damage payments and rental payments associated with salt water disposal contracts.

As of December 31, 2019, minimum future operating and finance lease payments and other commitments listed above for Contango's fiscal years are as follows (in thousands):

Fiscal years ending December 31,	
2020	$ 4,471
2021	2,810
2022	1,468
2023	1,282
2024	1,094
2025 and thereafter	919
Total	$ 12,044

The amounts incurred under operating and finance leases and payments related to delay rentals, surface use and salt water disposal contracts during the years ended December 31, 2019 and 2018 were approximately $1.5 million and $5.1 million, respectively.

Throughput Contract Commitment

The Company has a signed a throughput agreement with a third party pipeline owner/operator that constructed a natural gas gathering pipeline in the Company's Southeast Texas area that allows the Company to defray the cost of building the pipeline itself. Beginning in late 2016, the Company was unable to meet the minimum monthly gas volume deliveries through this line in its Southeast Texas area, and the volume will continue through the expiration of the throughput commitment on March 31, 2020. The throughput deficiency fee is paid in April of each calendar year. The Company incurred fees of $1.0 million, $1.0 million and $1.1 million during the years ended December 31, 2019, 2018 and 2017 respectively. As of December 31, 2019, the Company has recorded a $1.0 million loss contingency through the end of the contract in March 2020. The $1.0 million balance is payable on April 1, 2020.

Legal Proceedings

From time to time, the Company is involved in legal proceedings relating to claims associated with its properties, operations or business or arising from disputes with vendors in the normal course of business, including the material matters discussed below.

On November 16, 2010, a subsidiary of the Company, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in two wells that has not been recognized by the Company or by predecessor operators to which the Company had granted indemnification rights. In dispute is whether ownership rights were transferred through a number of decades-old poorly documented transactions. Based on prior summary judgments, the trial court entered a final judgment in the case in favor of the plaintiffs for approximately $5.3 million, plus post-judgment interest. The Company appealed the trial court's decision to the applicable state Court of Appeals, and in the fourth quarter of 2017, the Court of Appeals issued its opinion and affirmed the trial court's summary decision. In the first quarter of 2018, the Company filed a motion for rehearing with the Court of Appeals, which was denied, as expected. The Company filed a petition requesting a review by the Texas Supreme Court, as the Company believes the trial and appellate courts erred in the interpretation of the law. In early October 2019, the Texas Supreme Court notified the Company that it would not hear this case. The Company engaged additional legal representation to assist in the preparation of an amended petition requesting that the Texas Supreme Court reconsider its initial decision to not review the case. That amended petition was filed, and in mid-March 2020, the Texas Supreme Court decided they would not re-hear the case. Consequently, during the three months ended December 31, 2019, the Company recorded a $6.3 million liability for the judgment, interest and fees, with $3.5 million of such liability related to suspended funds currently reflected in "Accounts payable and accrued liabilities" on the Company's consolidated balance sheet.

On January 14, 2016, the Company was named as the defendant in a lawsuit filed in the District Court for Harris County in Texas by a third-party operator. The Company participated in the drilling of a well in 2012, which experienced serious difficulties during the initial drilling, which eventually led to the plugging and abandoning of the wellbore prior to reaching the target depth. In dispute is whether the Company is responsible for the additional costs related to the drilling difficulties and plugging and abandonment. In September 2019, the case went to trial, and, in October 2019, the court ruled in favor of the plaintiff. Prior to the judgment, the Company had approximately $1.1 million in accounts payable related to the disputed costs associated with this case. As a result of the judgment, during the three months ended September 30, 2019, the Company recorded an additional $2.1 million liability for the final judgment plus fees and interest. The Company has since prepared and filed an appeal with the appellate court for a review of the initial trial court decision and is awaiting the court's response.

While many of these matters involve inherent uncertainty and the Company is unable at the date of this filing to estimate an amount of possible loss with respect to certain of these matters, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on its consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company maintains various insurance policies that may provide coverage when certain types of legal proceedings are determined adversely.

Employment Agreements

On November 30, 2016, all of the Company's existing employment agreements expired through nonrenewal, and the Company and Mr. Keel, Mr. Grady, Mr. Mengle and Mr. Atkins entered into Amended and Restated Employment Agreements ("Employment Agreements"). The Employment Agreements provided for an initial term of three years for Messrs. Keel and Grady and an initial term of two years for Messrs. Mengle and Atkins. Each of the Employment Agreements automatically renews for additional one year terms, unless Contango or the executive provides prior notice of intention not to extend the agreement. Mr. Keel's employment agreement was terminated in conjunction with the Separation Agreement entered into between the Company and Mr. Keel on August 14, 2018. The employment agreements with Mr. Mengle and Mr. Atkins expired on November 30, 2018, and the employment agreement with Mr. Grady expired on November 30, 2019. No employment agreements were renewed pursuant to the Company's plan to phase out the use of employment agreements.

During the term of the Employment Agreements, Mr. Keel was entitled to a base salary of $600,000 until his resignation. Mr. Grady is entitled to a base salary of $400,000, Mr. Mengle was entitled to a base salary of $300,000 and Mr. Atkins was entitled to a base salary of $310,000. The Employment Agreements provided that each executive shall participate in the Company's CIBP and LTIP. With respect to the CIBP, the Employment Agreements provide that the executives are eligible to receive an annual cash incentive bonus with a target award level of 100% for Messrs. Keel and Grady and 80% for Messrs. Mengle and Atkins, of such executive's base salary, under such terms and conditions as the Company may determine each applicable year. With respect to the LTIP, the Employment Agreements provide that the executives are eligible to participate in the Company's equity compensation plan for each calendar year in which the executive is employed by the Company, under such terms and conditions as the Company may determine in each applicable year.

15. Net Loss Per Common Share

A reconciliation of the components of basic and diluted net loss per common share for the years ended December 31, 2019 and 2018 is presented below (in thousands):

	Year Ended December 31, 2019		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (159,796)	54,136	$ (2.95)
Diluted Earnings per Share:			
Effect of potential dilutive securities:			
Weighted average of incremental shares (stock options, restricted stock and PSUs)	—	—	—
Net loss attributable to common stock	$ (159,796)	54,136	$ (2.95)

	Year Ended December 31, 2018		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (121,568)	25,945	$ (4.69)
Diluted Earnings per Share:			
Effect of potential dilutive securities:			
Weighted average of incremental shares (stock options, restricted stock and PSUs)	—	—	—
Net loss attributable to common stock	$ (121,568)	25,945	$ (4.69)

The numerator for basic earnings per share is net loss attributable to common stockholders. The numerator for diluted earnings per share is net loss available to common stockholders.

Potential dilutive securities (stock options, restricted stock and PSUs) have not been considered when their effect would be antidilutive. The potentially dilutive shares would have been 613,506 shares and 1,141,707 shares for the years ended December 31, 2019 and 2018, respectively.

16. Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. The Company is subject to taxation in several jurisdictions, and the calculation of its tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

Income Tax Computation

Actual income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate rate of 21 percent for the years ended December 31, 2019 and 2018, respectively, to pretax income as follows (dollars in thousands):

	Year Ended December 31,			
	2019		2018	
Benefit at statutory tax rate	$ (33,561)	21.00 %	$ (25,504)	21.00 %
State income tax provision, net of federal benefit	555	(0.35)%	120	(0.10)%
Permanent differences	30	(0.02)%	579	(0.48)%
Stock based compensation	979	(0.61)%	1,353	(1.11)%
Valuation allowance	34,239	(21.42)%	21,941	(18.07)%
Other	(2,022)	1.26 %	1,631	(1.34)%
Income tax provision	$ 220	(0.14)%	$ 120	(0.10)%

The effective tax rate for the years ended December 31, 2019 and 2018 varies from the statutory rate primarily as a result of recording a valuation allowance.

The provision (benefit) for income taxes for the periods indicated are comprised of the following (in thousands):

	Year Ended December 31,	
	2019	2018
Current tax provision (benefit):		
Federal	$ (335)	$ —
State	555	120
Total	$ 220	$ 120
Deferred tax provision:		
Federal	$ —	$ —
State	—	—
Total	$ —	$ —
Total tax provision (benefit):		
Federal	$ (335)	$ —
State	555	120
Total	$ 220	$ 120
Included in gain (loss) from investment in affiliates	$ —	$ —
Total income tax provision	$ 220	$ 120

The net deferred tax is comprised of the following (in thousands):

	December 31, 2019	December 31, 2018
Deferred tax assets:		
Net operating loss carryforward	$ 81,571	$ 80,930
Income tax credits	—	454
Derivative instruments	377	—
Deferred compensation	—	678
Oil and gas properties	11,436	—
Investment in affiliates	2,799	—
Recognized built in loss	6,718	—
Other	2,549	1,529
Total deferred tax assets before valuation allowance	$ 105,450	$ 83,591
Valuation allowance	(105,212)	(70,973)
Net deferred tax assets	$ 238	$ 12,618
Deferred tax liability:		
Oil and gas properties	$ —	$ (11,042)
Investment in affiliates	—	(275)
Deferred compensation	(238)	—
Derivative instruments	—	(877)
Deferred tax liability	$ (238)	$ (12,194)
Total net deferred tax	$ —	$ 424

Accounting for uncertainty in income taxes prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities.

In assessing the realizability of deferred tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. 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. The Company considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the amount of deferred tax liabilities, level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, the Company believes it is not more-likely-than-not that it will realize the benefits of these deductible differences and has recorded a valuation allowance for federal and state purposes of approximately $104.2 million and approximately $1.0 million, respectively.

As of December 31, 2019, the Company had federal net operating loss ("NOL") carryforwards of approximately $383.9 million and state NOLs of $20.4 million. The Federal NOL carryforwards occurred due to the merger with Crimson Exploration, Inc. ("Crimson") in 2013 (the "Merger") and subsequent taxable losses during the years 2014 through 2019 due to lower commodity prices and utilization of various elections available to the Company in expensing capital expenditures incurred in the development of oil and gas properties. Generally, these NOLs are available to reduce future taxable income and the related income tax liability subject to the limitations set forth in Internal Revenue Code Section 382 related to changes of more than 50% of ownership of the Company's stock by 5% or greater shareholders over a three-year period (a Section 382 Ownership Change) from the time of such an ownership change. Recently passed legislation, however, temporarily suspends the Section 172 limitation for NOLs arising in a tax year beginning in 2018, 2019 or 2020 and also allows these NOLs to be carried back five years.

On November 19, 2018, the Company completed a follow-on offering (the "2018 Offering") of 7.5 million additional shares of common stock. Prior to December 18, 2018, the underwriters exercised their Green Shoe option purchasing an additional approximate 1.1 million shares, resulting in a total of approximately 8.6 million primary shares issued in the Offering. This issuance resulted in a Section 382 Ownership Change (the "2018 Ownership Change") which limits the Company's future ability to use its NOLs. As such, the Company is limited in use of NOLs for amounts incurred prior to November 20, 2018 in an amount estimated to be approximately $2.4 million per year (plus any recognized built in gains during the next five years) or until expiration of each annual vintage of NOL (generally, 20 years for each annual vintage of NOLs incurred prior to 2018).

On September 12, 2019, as discussed in Note 1 – "Organization and Business", the Company completed the September Public Offering which also resulted in a Section 382 Ownership Change on that date (the "2019 Ownership Change" and, together with the 2018 Ownership Change, the "Ownership Changes"). Due to changing market conditions, the Company's ability to utilize pre-2018 NOLs on that date could be limited to $700 thousand a year (in pre-tax dollars). This lower annual limitation resulting from the 2019 Ownership Change effectively eliminates the ability to utilize these tax attributes in the future.

The Company is also affected by the limitation in Section 163(j) on interest taken in any given tax year. As of December 31, 2019, the Company had a limitation of $2.4 million which will carry over indefinitely. Additionally, the Company's post-2017 NOLs of $96.6 million are also not subject to expiration, but are limited to offsetting 80% of the Company's taxable income in any year of usage after December 31, 2020. These carryovers are subject to any applicable Section 382 limitation (discussed above).

As a result of the Ownership Changes, the Company has recorded a valuation allowance against substantially all of its NOLs and other deferred tax assets. The valuation allowance balance at December 31, 2019 is $105.2 million.

ASC 740, Income Taxes ("ASC 740") prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. As a result of the Merger, the Company acquired certain tax positions taken by Crimson in prior years. These positions are not expected to have a material impact on results of operations, financial position or cash flows. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows (in thousands):

	Unrecognized Tax Benefits
Balance at December 31, 2018	$ 227
Additions based on tax positions related to the current year	—
Additions based on tax positions related to prior years	—
Additions due to acquisitions	—
Reductions due to a lapse of the applicable statute of limitations	(227)
Change in rate due to remeasurement	—
Balance at December 31, 2019	$ —

The Company's policy is to recognize interest and penalties related to uncertain tax positions as income tax benefit (expense) in the Company's Consolidated Statements of Operations. The Company had no interest or penalties related to unrecognized tax benefits for the year ended December 31, 2019 or any prior years. The total amount of unrecognized tax benefit, if recognized, that would affect the effective tax rate was zero.

The Company's tax returns are subject to periodic audits by the various jurisdictions in which the Company operates. These audits can result in adjustments of taxes due or adjustments of the NOL carryforwards that are available to offset future taxable income. The Company does not anticipate that the total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of the statute of limitations prior to December 31, 2019.

Generally, the Company's income tax years of 2009 through 2019 remain open and subject to examination by Federal tax authorities, and the tax years of 2009 through 2019 remain open and subject to examination by the tax authorities in Texas and Louisiana which are the jurisdictions where the Company carries its principal operations.

17. Subsequent Events

In December 2019, a novel strain of coronavirus (SARS-Cov-2), which causes COVID-19, was reported to have surfaced in China. The spread of this virus has caused business disruption beginning in January 2020, including disruption to the oil and natural gas industry. In March 2020, the World Health Organization declared the outbreak of COVID-19 to be a pandemic, and the U.S. economy began to experience pronounced effects. The extent of the impact of the COVID-19 pandemic on the Company's operational and financial performance, including the Company's ability to execute its business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including, but not limited to, the demand for oil and natural gas, the availability of personnel, goods and services critical to the Company's ability to operate its properties and potential governmental restrictions. While the disruption is currently expected to be temporary, there is uncertainty around the extent and duration. Therefore, while the Company expects this matter will likely disrupt its operations in some way, the related financial impact of any such disruption cannot be reasonably estimated at this time.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited)

In accordance with U.S. GAAP for disclosures regarding oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures regarding our natural gas and oil reserves and exploration and production activities.

Capitalized Costs Related to Oil and Gas Producing Activities

The following table presents information regarding our net capitalized costs related to oil and gas producing activities as of the date indicated (in thousands):

	December 31,	
	2019	2018
Proved oil and gas properties	$ 1,306,916	$ 1,095,417
Unproved oil and gas properties	27,619	34,612
	1,334,535	1,130,029
Less accumulated depreciation, depletion, amortization and impairment	(1,043,668)	(897,140)
Net capitalized costs	$ 290,867	$ 232,889

Costs Incurred

The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated (in thousands):

	Year Ended December 31,	
	2019	2018
Property acquisition costs:		
Unproved	$ 12,486	$ 10,339
Proved	168,838	—
Exploration costs	1,003	1,637
Development costs	41,273	42,516
Total costs incurred	$ 223,600	$ 54,492

The following table presents information regarding our share of the net costs incurred by Exaro in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated (in thousands):

	Year Ended December 31,	
	2019	2018
Property acquisition costs	$ —	$ —
Exploration costs	17	—
Development costs	72	169
Total costs incurred	$ 89	$ 169

Natural Gas and Oil Reserves

Proved reserves are the estimated quantities of natural gas, oil and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and current regulatory practices. Proved developed reserves are proved reserves which are expected to be produced from existing completion intervals with existing equipment and operating methods.

Proved natural gas and oil reserve quantities at December 31, 2019, 2018 and 2017, and the related discounted future net cash flows before income taxes are based on estimates prepared by William M. Cobb & Associates, Inc. and Netherland, Sewell & Associates, Inc. All estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The below table summarizes the Company's net ownership interests in estimated quantities of proved natural gas, oil and natural gas liquids ("NGLs") reserves and changes in net proved reserves as of December 31, 2019, 2018 and 2017, all of which are located in the continental United States.

	Oil and Condensate (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Proved Developed and Undeveloped Reserves as of:				
December 31, 2017	10,649	5,607	91,719	189,254
Sale of minerals in place	(1,914)	(519)	(10,636)	(25,234)
Extensions and discoveries	3,977	795	4,499	33,136
Revisions of previous estimates	(2,708)	(1,893)	(21,597)	(49,206)
Production	(570)	(473)	(9,779)	(16,039)
December 31, 2018	9,434	3,517	54,206	131,911
Sale of minerals in place	(1)	(12)	(371)	(449)
Acquisitions	7,718	9,103	91,765	192,688
Extensions and discoveries	9,788	1,457	9,581	77,051
Revisions of previous estimates	(7,063)	(1,689)	(14,359)	(66,872)
Production	(791)	(612)	(9,522)	(17,940)
December 31, 2019	19,085	11,764	131,300	316,389
Proved Developed Reserves as of:				
December 31, 2017	3,364	3,596	82,133	123,895
December 31, 2018	3,103	2,297	46,840	79,234
December 31, 2019	9,819	10,484	122,691	244,515
Proved Undeveloped Reserves as of:				
December 31, 2017	7,285	2,011	9,586	65,359
December 31, 2018	6,331	1,220	7,366	52,677
December 31, 2019	9,266	1,280	8,609	71,874

During the year ended December 31, 2019, our proved reserves increased by approximately 184.5 Bcfe primarily due to the 192.7 Bcfe increase related to the White Star and Will Energy acquisitions, as well as an increase in total reserves attributable to our recently drilled wells in the NE Bullseye area of West Texas, offset by 2019 production and a downward revision in Bullseye PUDs in West Texas related to the impact of the low commodity price environment on economics in the area, and the related timeline for expected development of those PUD locations over the next five years.

During the year ended December 31, 2018, our proved reserves declined by approximately 57.3 Bcfe primarily due to property sales throughout the year, a negative revision related to our West Texas type curve resulting from analysis of longer term decline experience and a decrease in our GOM developed reserves related to negative revisions as a result of new bottom hole pressure data gathered during the planned installation of a second stage of compression in the Eugene Island 11 field. Partially offsetting these reserve decreases were new additions and extensions related to our drilling program.

The below table summarizes the Company's net ownership interests in estimated quantities of proved natural gas and oil reserves and changes in net proved reserves as of December 31, 2019, 2018 and 2017, attributable to its equity investment in Exaro.

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Proved Developed and Undeveloped Reserves as of:			
December 31, 2017	329	28,746	30,719
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Revisions of previous estimates	(28)	(1,043)	(1,212)
Production	(29)	(2,738)	(2,912)
December 31, 2018	272	24,965	26,595
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Revisions of previous estimates	(23)	(1,052)	(1,190)
Production	(24)	(2,306)	(2,450)
December 31, 2019	225	21,607	22,955
Proved Developed Reserves as of:			
December 31, 2017	325	28,443	30,390
December 31, 2018	272	24,965	26,595
December 31, 2019	225	21,607	22,955
Proved Undeveloped Reserves as of:			
December 31, 2017	4	303	329
December 31, 2018	—	—	—
December 31, 2019	—	—	—

During the year ended December 31, 2019, the decrease in Exaro's proved reserves attributable to our Investment in Exaro was approximately 3.6 Bcfe.

During the year ended December 31, 2018, the decrease in Exaro's proved reserves attributable to our Investment in Exaro was approximately 4.1 Bcfe.

Standardized Measure

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved natural gas and oil reserves as of December 31, 2019 and 2018 are shown below (in thousands):

	As of December 31, 2019	2018
Future cash inflows	$ 1,519,882	$ 854,869
Future production costs	(782,031)	(271,679)
Future development costs	(217,782)	(165,919)
Future income tax expenses	(43,913)	(3,407)
Future net cash flows	476,156	413,864
10% annual discount for estimated timing of cash flows	(218,314)	(194,920)
Standardized measure of discounted future net cash flows	$ 257,842	$ 218,944

Future cash inflows represent expected revenues from production and are computed by applying certain prices of natural gas and oil to estimated quantities of proved natural gas and oil reserves. Prices are based on the first-day-of-the-month prices for the previous 12 months. As of December 31, 2019, future cash inflows were based on unadjusted prices of $2.52 per MMbtu of natural gas, $55.69 per barrel of oil and $16.95 per barrel of NGLs. As of December 31, 2018, future cash inflows were based on unadjusted prices of $3.10 per MMbtu of natural gas, $64.80 per barrel of oil and $27.89 per barrel of NGLs.

The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved natural gas and oil reserves as of December 31, 2019 and 2018 attributable to its equity investment in Exaro are shown below (in thousands):

	As of December 31, 2019	As of December 31, 2018
Future cash inflows	$ 74,684	$ 91,792
Future production costs	(48,863)	(55,448)
Future development costs	(2,267)	(2,268)
Future income tax expenses (1)	—	—
Future net cash flows	23,554	34,076
10% annual discount for estimated timing of cash flows	(8,246)	(13,075)
Standardized measure of discounted future net cash flows	$ 15,308	$ 21,001

(1) Exaro does not include the effect of income taxes because Exaro is treated as a partnership for tax purposes.

Realized Prices

The average realized prices for the year ended December 31, 2019 production were $2.35 per MCF of gas, $56.55 per barrel of oil, and $15.39 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging gains of $2.6 million for the year ended December 31, 2019.

The average realized prices for the year ended December 31, 2018 production were $3.05 per MCF of gas, $60.43 per barrel of oil, and $27.04 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging losses of $3.5 million for the year ended December 31, 2018.

Future production and development costs are estimated expenditures to be incurred in developing and producing the Company's proved natural gas and oil reserves based on historical costs and assuming continuation of existing economic conditions. Future development costs relate to compression charges at our platforms, abandonment costs, recompletion costs and additional development costs for new facilities.

Future income taxes are based on year-end statutory rates, adjusted for tax basis and applicable tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company's natural gas and oil properties. 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 of natural gas and oil producing operations.

Change in Standardized Measure

Changes in the standardized measure of future net cash flows relating to proved natural gas and oil reserves are summarized below (in thousands):

	Year Ended December 31, 2019	Year Ended December 31, 2018
Changes in standardized measure due to current year operation:		
Sales of natural gas and oil produced during the period, net of production expenses	$ (55,868)	$ (51,496)
Extensions and discoveries	54,308	46,732
Net change in prices and production costs	(67,470)	33,195
Changes in estimated future development costs	16,223	(2,096)
Revisions in quantity estimates	(77,309)	(58,063)
Purchase of reserves	177,007	—
Sale of reserves	(246)	(38,257)
Previously estimated development costs incurred	2,958	4,467
Accretion of discount	22,051	25,728
Changes in income taxes	(27,148)	(188)
Change in the timing of production rates and other	(5,608)	3,015
Net change	38,898	(36,963)
Beginning of year	218,944	255,907
End of year	$ 257,842	$ 218,944

During the year ended December 31, 2019, our proved reserves increased by approximately 184.5 Bcfe, and our standardized measure increased by approximately $38.9 million. This increase is primarily attributable to the Will Energy and White Star acquisitions.

During the year ended December 31, 2018, our proved reserves decreased by approximately 57.3 Bcfe, and our standardized measure decreased by approximately $37.0 million. This decrease is primarily attributable to non-core property sales throughout the year and negative revisions of reserve estimates due to a revision of our West Texas type curve as discussed above and the previously disclosed revision to the Eugene Island field as a result of new bottom hole pressure data gathered during the planned installation of a second stage of compression.

Changes in the standardized measure of future net cash flows relating to proved natural gas and oil reserves attributable to the Company’s equity investment in Exaro are summarized below (in thousands):

	Year Ended December 31, 2019	Year Ended December 31, 2018
Changes in standardized measure due to current year operation:		
Sales of natural gas and oil produced during the period, net of production expenses	$ (4,343)	$ (5,056)
Net change in prices and production costs	(2,423)	1,024
Changes in estimated future development costs	—	7
Revisions in quantity estimates	(940)	(808)
Previously estimated development costs incurred	—	99
Accretion of discount	2,099	2,437
Change in the timing of production rates and other	(86)	(1,068)
Net change	(5,693)	(3,365)
Beginning of year	21,001	24,366
End of year	$ 15,308	$ 21,001

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Quarterly Results of Operations

The following table sets forth the results of operations by quarter for the fiscal years ended December 31, 2019 and 2018 (in thousands, except per share amounts):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
Year ended December 31, 2019:				
Revenues	$ 14,011	$ 12,762	$ 12,547	$ 37,193
Operating Loss [(1)]	$ (4,553)	$ (6,457)	$ (8,794)	$ (130,926)
Net loss attributable to common stock [(2)]	$ (8,618)	$ (4,961)	$ (7,838)	$ (138,379)
Net loss per share [(3)]:				
Basic:	$ (0.26)	$ (0.15)	$ (0.19)	$ (1.32)
Diluted:	$ (0.26)	$ (0.15)	$ (0.19)	$ (1.32)
Year ended December 31, 2018:				
Revenues	$ 20,437	$ 18,448	$ 19,508	$ 18,694
Operating Loss [(1)]	$ (7,497)	$ (4,053)	$ (79,400)	$ (28,698)
Net income (loss) attributable to common stock [(2)]	937	(7,178)	(81,524)	(33,803)
Net income (loss) per share [(3)]:				
Basic:	$ 0.04	$ (0.29)	$ (3.26)	$ (1.16)
Diluted:	$ 0.04	$ (0.29)	$ (3.26)	$ (1.16)

(1) Represents natural gas, oil and NGL sales, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of natural gas and oil properties and general and administrative expense.

(2) Represents natural gas ,oil and NGL sales, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of natural gas and oil properties, general and administrative expense, and other income and expense after income taxes.

(3) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share as each quarterly computation is based on the income for that quarter and the weighted average number of common shares outstanding during that quarter.

Exhibit 4.5

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES AND EXCHANGE ACT OF 1934

General

The authorized capital stock of Contango Oil & Gas Company (the "Company", "we", "us" and "our") consists of 205,000,000 shares, which includes 200,000,000 shares authorized as common stock, $0.04 par value, and 5,000,000 shares authorized as preferred stock, $0.04 par value. As of March 23, 2020, we had: (i) 228 holders of record of common stock and 129,122,673 shares of common stock outstanding; (ii) no shares of Series A Contingent Convertible Preferred Stock, par value $0.04 ("Series A Preferred Stock") outstanding; (iii) no Series B Contingent Convertible Preferred Stock, par value $0.04 ("Series B Preferred Stock") outstanding; and (iv) eight holders of record of Series C Contingent Convertible Preferred Stock, par value $0.04 ("Series C Preferred Stock"), and 2,700,000 shares of Series C Preferred Stock outstanding.

Description of Common Stock

The following description sets forth certain material terms and provisions of our common stock, which is registered under Section 12 of the Securities Exchange Act of 1934, as amended. The following description of our common stock is not complete and is qualified in its entirety by reference to our amended and restated certificate of formation (including any statement of resolution of preferred stock) and our bylaws, which are filed as exhibits to our Annual Report on Form 10-K.

Dividends. Holders of common stock are entitled to such dividends as may be declared by the board of directors (the "Board") out of funds legally available. Any decision to pay future dividends on our common stock will be at the discretion of our Board and will depend upon our financial condition, results of operations, capital requirements and other factors our Board may deem relevant. Our credit facility currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Fully Paid. All outstanding shares of common stock are fully paid and non-assessable upon issuance.

Voting Rights. Holders of common stock are entitled to one vote per share with respect to each matter presented to our stockholders on which the holders of common stock are entitled to vote. Common stockholders are not entitled to preemptive or cumulative voting rights. Unless specified in our amended and restated certificate of formation (including any statement of resolution of preferred stock) or the bylaws of the Company, or as required by applicable provisions of the Texas Business Organizations Code (the "TBOC") or applicable stock exchange rules, the affirmative vote of the holders of a majority of the voting power of the outstanding shares of the Company entitled to vote on a matter is required to approve any such matter voted on by the Company's stockholders.

Other Rights. In the event of a liquidation, dissolution or winding up of the Company, the holders of the common stock are entitled to share ratably in all assets remaining available for distribution to them after payment of liabilities and after provision is made for each class of stock, if any, having preference over the common stock. No share of common stock is convertible, redeemable, assessable or entitled to the benefits of any sinking or repurchase fund.

Transfer Agent and Registrar. Our transfer agent and registrar for our common stock, Series A Preferred Stock, Series B Preferred Stock, and Series C Preferred Stock is Continental Stock Transfer & Trust Company, LLC, located in New York, New York.

Listing. Our common stock is listed on the NYSE American and trades under the symbol “MCF.”

Description of Preferred Stock

The following descriptions set forth certain material terms and provisions of our series of preferred stock, which are not registered under Section 12 of the Exchange Act. The following descriptions of our preferred stock are not complete and are qualified in their entirety by reference to our amended and restated certificate of formation (including any statement of resolution of preferred stock) and our bylaws, which are filed as exhibits to our Annual Report on Form 10-K.

Our amended and restated certificate of formation authorizes 5,000,000 shares of preferred stock and provides that shares of preferred stock may be issued from time to time in one or more series. Our Board is expressly granted authority to fix for each such series such voting powers, full or limited, and such designations, preferences and relative, participating, optional or other special rights and such qualifications, limitations or restrictions thereof as shall be stated and expressed in the resolution or resolutions adopted by the Board providing for the issue of such series and as may be permitted by the TBOC.

In September and November 2019, the Company established and issued Series A Preferred Stock and Series B Preferred Stock. On December 12, 2019, the outstanding shares of Series A Preferred Stock and Series B Preferred Stock automatically converted into common stock and, upon the conversion, all outstanding shares of Series A Preferred Stock and Series B Preferred Stock were cancelled.

The Series C Preferred Stock ranks equal to the common stock, the Series A Preferred Stock and the Series B Preferred Stock with respect to dividend rights and rights upon liquidation. The Series C Preferred Stock has no voting rights. Upon shareholder approval, each share of Series C Preferred Stock will automatically convert into one common share and the outstanding shares of Series C Preferred Stock will be cancelled.

No dividends shall accrue or be payable on the Series C Preferred Stock until December 23, 2020. Holders of the Series C Preferred Stock are entitled to receive, when and as declared by the Board and declared by the Company, cash dividends of ten percent (10%) of the $2.50 original issue price per annum on each outstanding share of Series C Preferred Stock. Such dividends shall accrue from December 23, 2020. Following such date, subject to compliance with the Company’s credit agreement, dividends shall be payable quarterly in cash on March 31, June 30, September 30 and December 31 of each year, beginning December 31, 2020, when, as and if declared by the Board, and shall cease to accrue on the date immediately preceding the date of conversion of the Series C Preferred Stock to common stock; provided, however, when there are no shares of Series C Preferred Stock outstanding, no dividends, including any dividends which have accrued, shall be payable to the holders of the shares of Series C Preferred Stock or the holders of the shares of common stock into which the shares of Series C Preferred Stock convert.

Certain Provisions of Our Amended and Restated Certificate of Formation, Bylaws and Law

Our amended and restated certificate of formation and bylaws contain provisions that may render more difficult possible takeover proposals to acquire control of us and make removal of our management more difficult. Below is a description of certain of these provisions in our amended and restated certificate of formation and bylaws.

Anti-takeover Statute

Pursuant to our governing documents, the Company has opted out of TBOC §21.606 (the “Texas Anti-takeover Statute”); however, our bylaws incorporate anti-takeover provisions (the “Bylaw Anti-takeover Provisions”) that are based on the Texas Anti-takeover Statute. These Bylaw Anti-takeover Provisions give us flexibility to engage in certain beneficial transactions with any of our shareholder while still providing the appropriate level of anti-takeover protections for a corporation of our size and shareholder base. Specifically, the Bylaw Anti-takeover Provisions include substantially the same restrictions that are provided for under the Texas Anti-takeover Statute, provided that those restrictions do not apply to (i) John Goff and his affiliated funds at any time that they own less than 23% of the Company’s outstanding shares (or such higher ownership threshold as may be approved by the Board in advance) or (ii) a transaction between the Company and any person that holds more than 20% of the Company’s outstanding shares if such transaction is approved in advance by (A) a majority of the continuing and unaffiliated directors of the Company and (B) holders of a majority of the Company’s outstanding shares.

Board

Our amended and restated certificate of formation provides that the Board shall consist of such number of directors as shall be determined from time to time solely by resolution adopted by the affirmative vote of a majority of the total number of directors then authorized, but no reduction of the number of directors shall have the effect of removing any director prior to the expiration of his term of office. Our amended and restated certificate of formation further provides that this provision may not be amended or repealed except upon the affirmative vote of the holders of at least sixty-six and two-thirds percent (66 2/3%) of the voting power of all of the then-outstanding shares of the voting stock of the Company, voting together as a single class. Voting stock means the voting power of the outstanding shares of the Company entitled to vote generally in the election of directors.

Stockholder Meetings

Our bylaws limit the ability of our stockholders to call meetings of stockholders. Meetings of the stockholders may be called at any time by the Board, in its sole discretion, except that the Board shall be required to call a special meeting of stockholders on the written request in proper form of the holder or holders of at least one-half (1/2) of all the shares outstanding and entitled to vote thereat. Our bylaws require that written notice, stating the place, day and hour of the meeting and the purpose or purposes for which the meeting is called, shall be prepared and delivered by us not less than ten (10) days nor more than sixty (60) days before the date of a stockholder meeting, except as otherwise provided in our bylaws or required by law.

Director Nominations

Our bylaws contain specific procedures for stockholder nomination of directors. These provisions require advance notification that must be given in accordance with the provisions of our bylaws. The procedure for stockholder nomination of directors may have the effect of precluding a nomination for the election of directors at a particular meeting if the required procedure is not followed.

Annual Meeting

Our bylaws also contain specific procedures for a stockholder to properly bring business before the annual meeting. These provisions require advanced notification that must be given in accordance with the provisions of our bylaws. The procedure for bringing business before the annual meeting may have the effect of precluding a stockholder from bringing such business at the annual meeting if the required procedure is not followed.

Voting

Although Section 21.361 of the TBOC provides that a corporation’s certificate of formation may provide for cumulative voting for directors, neither our amended and restated certificate of formation nor our bylaws provide for cumulative voting. As a result, the holders of a majority of the votes of the outstanding shares of our common stock have the ability to elect all of the directors being elected at any annual meeting of stockholders.

Liability and Indemnification of Officers and Directors

Our amended and restated certificate of formation provides for indemnification of our directors and officers to the full extent permitted by applicable law. Our bylaws also provide that directors and officers shall be indemnified against liabilities arising from their service as directors or officers.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling the registrant pursuant to the foregoing provisions, we have been informed that, in the opinion of the Securities and Exchange Commission, such indemnification is against public policy as expressed in the Securities Act and is therefore unenforceable.

Forum for Shareholder Litigation

Our bylaws provide, subject to limited exceptions, that the United States District Court for the Southern District of Texas will be the sole and exclusive forum for certain stockholder litigation matters. Unless we consent to the selection of an alternative forum, the United States District Court for the Southern District of Texas or, if such court lacks jurisdiction, the state district court of Harris County, Texas, shall, to the fullest extent permitted by law, be the sole and exclusive forum for any (i) derivative action or proceeding brought in the name or right of the Company or on its behalf, (ii) action asserting a claim for breach of a fiduciary duty owed by any director, officer, employee or other agent of the Company to the Company or the Company's stockholders, (iii) action asserting a claim arising pursuant to any provision of the TBOC, or our certificate of incorporation or bylaws, or (iv) action asserting a claim governed by the internal affairs doctrine. Such restrictions could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or stockholders.

Exhibit 21.1

CONTANGO OIL AND GAS COMPANY
LIST OF WHOLLY-OWNED SUBSIDIARIES
DECEMBER 31, 2019

Wholly-Owned Subsidiaries of Contango Oil & Gas Company as of 12/31/19

Crimson Exploration Inc.
Crimson Exploration Operating, Inc.
Contango Resources, Inc.
Contango Midstream Company
Contango Energy Company
Contango Rocky Mountain Inc.
Contango Operators, Inc.
Contango Mining Company
Conterra Company
Contaro Company
Contango Alta Investments, Inc.
Contango Venture Capital Corporation
LTW Pipeline Co.

Exhibit 21.2

CONTANGO OIL & GAS COMPANY
Corporate Structure
December 31, 2019

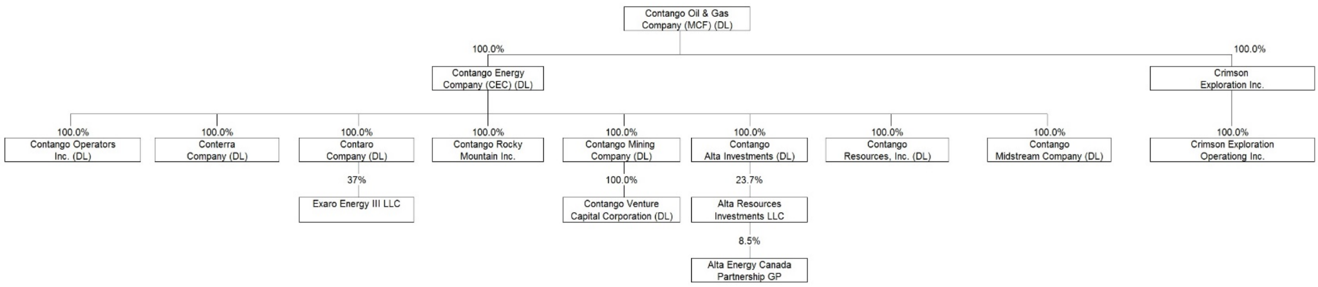

Exhibit 23.1

WILLIAM M. COBB & ASSOCIATES, INC.

Worldwide Petroleum Consultants

12770 Coit Road, Suite 907
Dallas, Texas 75251

(972) 385-0354
Fax: (972) 788-5165
E-Mail: office@wmcobb.com

March 30, 2020

Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, Texas 77002

Re: Contango Oil & Gas Company, Annual Report on Form 10-K

Gentlemen:

The firm of William M. Cobb & Associates, Inc. consents to the use of its name and to the use of its projections for Contango Oil & Gas Company's Proved Reserves and Future Net Revenue in Contango's Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

We consent to the incorporation by reference of said reports in the Registration Statements of Contango Oil & Gas Company on Forms S-3 (File No. 333-215784 and File No. 333-235934) and on Forms S-8 (File No. 333-229336, File No. 333-189302 and File No. 333-170236).

William M. Cobb & Associates, Inc. has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Sincerely,

WILLIAM M. COBB & ASSOCIATES, INC.
Texas Registered Engineering Firm F-84

Frank J. Marek, P.E.
President

STATE OF TEXAS
FRANK J. MAREK
52939
REGISTERED
PROFESSIONAL ENGINEER

W.D.Von Gonten&Co.
Petroleum Engineering 10496 Old Katy Road, Suite 200 Houston, Texas 77043 *t*:713 224 6333 *f*: 713.224.6330 www.wdygco.com

W.D. VON GONTEN & CO.

March 30, 2020

Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, Texas 77002

Re: Contango Oil & Gas Company, Annual Report on Form 10-K

Gentlemen:

The firm of W.D. Von Gonten & Co. consents to the use of its name and to the use of its report regarding Contango Oil & Gas Company's Proved Reserves and Future Net Revenue associated with its 37% ownership interest in Exaro Energy III LLC, in Contango's Annual Report on Form 10-K for the fiscal year ended December 31, 2019.

We consent to the incorporation by reference of said reports in the Registration Statements of Contango Oil & Gas Company on Forms S-3 (File No. 333 215784 and File No. 333-235934) and on Forms S-8 (File No. 333-229336, File No. 333-189302 and File No. 333-170236).

W.D. Von Gonten & Co. has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Yours very truly,

W.D. VON GONTEN & CO.

Name: W.D. Von Gonten JR
Title: President

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 30, 2020, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Contango Oil & Gas Company on Form 10-K for the year ended December 31, 2019. We consent to the incorporation by reference of said reports in the Registration Statements of Contango Oil & Gas Company on Forms S-3 (File No. 333-215784 and File No. 333-235934) and on Forms S-8 (File No. 333-229336, File No. 333-189302 and File No. 333-170236).

/s/ GRANT THORNTON LLP

Houston, Texas

March 30, 2020

Exhibit 31.1

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, Wilkie S. Colyer, President and Chief Executive Officer of Contango Oil & Gas Company (the “Company”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Company;

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 Company as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company 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 Company, 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 Company’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 Company’s internal control over financial reporting that occurred during the Company’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company’s auditors and the audit committee of the Company’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 Company’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 Company’s internal control over financial reporting.

Date: March 30, 2020

By: /s/ WILKIE S. COLYER

Wilkie S. Colyer
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, E. Joseph Grady, Chief Financial Officer of Contango Oil & Gas Company (the "Company"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Company;

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 Company as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Company 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 Company, 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 Company'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 Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company'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 Company'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 Company's internal control over financial reporting.

Date: March 30, 2020

By: /s/ E. JOSEPH GRADY

E. Joseph Grady
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CONTANGO OIL & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Contango Oil & Gas Company (the “Company”) on Form 10-K for the year ended December 31, 2019 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, Wilkie S. Colyer, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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 30, 2020

By: /s/ WILKIE S. COLYER

Wilkie S. Colyer
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 32.2

CONTANGO OIL & GAS COMPANY

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Contango Oil & Gas Company (the "Company") on Form 10-K for the year ended December 31, 2019 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, E. Joseph Grady, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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 30, 2020

By: /s/ E. JOSEPH GRADY

E. Joseph Grady
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.1

WILLIAM M. COBB & ASSOCIATES, INC.

Worldwide Petroleum Consultants

12770 Coit Road, Suite 907
Dallas, Texas

(972) 385-0354
Fax: (972) 788-5165
E-Mail: office@wmcobb.com

March 2, 2020

Ms. Christie Schultz
Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, TX 77002

Dear Ms. Schultz:

In accordance with your request, William M. Cobb & Associates, Inc. (Cobb & Associates) has estimated the proved reserves and future income as of January 1, 2020, attributable to the interest of Contango Oil & Gas Company and its subsidiaries (Contango) in certain oil and gas properties located in Oklahoma, Texas, Louisiana, state and federal waters of the Gulf of Mexico, Wyoming, Mississippi, and Kansas. This report is an evaluation of Contango legacy properties and the properties acquired from Will Energy (Will legacy) and White Star Petroleum (White Star legacy) by Contango in October and November 2019.

Reserves presented in this report are classified as proved and are further categorized as proved developed producing (PDP), proved non-producing (PNP), proved shut-in (PSI), and proved undeveloped (PUD). Table 1 summarizes our estimate of the proved oil and gas reserves and their pre-federal income tax value undiscounted and discounted at ten percent using SEC pricing. Table 2 summarizes our estimate of the proved oil and gas reserves and their pre-federal income tax value undiscounted and discounted at ten percent using the December 31, 2019 NYMEX strip price.

TABLE 1

CONTANGO OIL AND GAS
TOTAL PROVED RESERVES AND CASH FLOW SUMMARY
YEAR-END SEC 2019 PRICE

	Net Reserves			Future Net Cash Flow	
Reserves Category	**Oil (MBBL)**	**Gas (MMCF)**	**NGL (MBBL)**	**Undisc. (M$)**	**Disc. 10% (M$)**
1PDP	9,815	122,033	10,476	371,753	261,922
3PNP	4	658	8	926	758
4SI	0	0	0	0	0
5PUD	9,265	8,609	1,279	147,391	23,873
TOTAL PROVED	**19,085**	**131,300**	**11,763**	**520,069**	**286,553**

TABLE 2

CONTANGO OIL AND GAS
TOTAL PROVED RESERVES AND CASH FLOW SUMMARY
12/31/2019 NYMEX STRIP PRICE

	Net Reserves			Future Net Cash Flow	
Reserves Category	**Oil (MBBL)**	**Gas (MMCF)**	**NGL (MBBL)**	**Undisc. (M$)**	**Disc. 10% (M$)**
1PDP	9,525	121,813	10,317	349,643	247,762
3PNP	4	658	8	836	682
4SI	0	0	0	0	0
5PUD	4,443	4,638	666	61,365	13,120
TOTAL PROVED	**13,972**	**127,109**	**10,991**	**411,844**	**261,564**

Values shown were determined utilizing constant oil and gas prices and well operating expenses. The discounted present worth of future income values shown in Table 1 and Table 2 are not intended to represent an estimate of fair market value. These estimates were prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Certification Topic 932, Extraction Activities – Oil and Gas.

Reserve and cash flow summary projections and a one-line summary for total proved reserves by category are detailed in Appendix A for the SEC price case. Appendix B includes a cash flow and one-line summary of reserves by region and field and reserve category for the SEC price case. Appendix C includes the cash flow projections and one-line summary by category for the strip price case. Cash flow projections and a one-line summary for the strip price case, by region and field and reserve category are detailed in Appendix D.

Oil and NGL volumes are expressed in thousands of stock tank barrels (MBBL). A stock tank barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of standard cubic feet (MMCF) as determined at 60° Fahrenheit and the legal pressure base for the specific location of the gas reserves.

This report, which was prepared for Contango's use in filing with the SEC and will be filed with Contango's Form 10-K for fiscal year ending December 31, 2019 (the "Form 10-K") and covers 100 percent of the total company present value discounted at ten percent (PV10) presented in Contango's Form 10-K. All assumptions, data, methods, and procedures considered necessary and appropriate were used to prepare this report.

DISCUSSION

The Contango legacy properties attribute 41 percent of the total proved discounted present value and are located in state and federal waters offshore Louisiana in the Gulf of Mexico, and onshore in Texas, Louisiana, and Wyoming. In a transaction that closed on November 1, 2019, Contango acquired White Star Petroleum. The White Star legacy properties attribute 50 percent of the total proved discounted present value and are located in Oklahoma. Will Energy was acquired by Contango in a transaction that closed on October 25, 2019. The Will legacy properties attribute the remaining nine percent of the total proved discounted present value. These properties are located in Oklahoma and north Louisiana.

Reserve estimates were prepared using generally accepted petroleum engineering principles and practices. The method, or combination of methods, utilized in the study of each property or reservoir included an assessment of the stage of reservoir development, quality of data, and length of production history. Geologic and engineering data was obtained from Contango, public sources, and the non-confidential files of Cobb & Associates.

Performance data through December of 2019 was used to forecast reserves for all producing properties where available. Reserve classification was based on the status of each well as of January 1, 2020 for operated wells, and on the most recently available information for non-operated wells.

For most regions in the report, the PDP reserve estimates were based on decline curve analysis. Some of the properties have produced for only a short period of time and did not exhibit an identifiable performance decline trend. In these cases, reserve estimates were based primarily on geological interpretation, mapping, and analogy to offset producers. Past performance, and offsetting performance data were used to estimate behind pipe and undeveloped reserves. Fields where additional analysis or methodology was used for the reserve assignments are discussed in more detail. These fields include Eugene Island 11 and properties in west Texas.

Offshore - Eugene Island 11

Eugene Island 11 is located in federal and Louisiana state waters of the Gulf of Mexico, at a water depth of approximately 13 feet. Production is primarily from a single CibOp sand, the JRM-1 sand, at a depth of approximately 15,000 feet. The field was discovered in September, 2006 by the Contango Operators Dutch 1 well. Contango has since drilled four more wells, the Dutch 2, 3, 4 and 5, on Federal acreage. All five of the Dutch wells are currently active.

Contango also has properties in Louisiana state waters in this field. These properties are referred to as the Mary Rose prospect. Five Mary Rose wells have been drilled to date. Four Mary Rose wells, numbers 1 through 4, have produced from the main CibOp sand. The Mary Rose 4 well is depleted and has been abandoned. The Mary Rose 3 is also depleted, with abandonment scheduled for May 2020.

The Mary Rose 5 well produced from a separate, and much smaller, CibOp reservoir that is now depleted. Abandonment of the Mary Rose 5 was completed in 2019.

Proved reserves for the Eugene Island 11 main CibOp sand are based on analysis of historical rate versus time decline curves and P/Z performance plots, supplemented by volumetric calculations of original-gas-in-place (OGIP) using all available well log and 3D seismic data. The reservoir has been effectively drilled to the lowest structural datum and no significant aquifer has been found. Performance to date indicates a depletion drive system.

All Dutch and Mary Rose wells now flow to compression on the ‘H’ platform, allowing for a decrease in producing flowing tubing pressures. This two-stage compression lowers line pressure to approximately 200 psi. There are no remaining capital or startup costs for compression on the ‘H’ platform. Abandonment costs were provided by Contango and scheduled at the end-of-project life for all wells and the ‘H’ platform.

West Texas – Bullseye and North East Bullseye

During 2017, Contango embarked on a drilling program for Wolfcamp Shale wells in Pecos County, Texas. This program is divided into two areas, Bullseye and north east Bullseye. In the Bullseye area, 14 wells have been drilled and completed and are carried as proved developed producing (PDP) in this report. Three wells have been drilled and completed and are currently producing as of January 1, 2020 in the north east Bullseye area.

To supplement decline curve analysis, simulation software was used to develop production curves for each well taking in account bottom hole pressures and additional reservoir data. Proved undeveloped (PUD) locations were assigned to each lease such that there are a maximum of six wells total per lease at both Bullseye and north east Bullseye areas. Reserves were assigned to the PUD locations using a type curve developed from an analysis of the PDP wells and offsetting wells in the surrounding leases and average PDP assigned recoveries.

OIL AND GAS PRICING

For the SEC price case, projections of proved reserves contained in this report utilize constant product prices of $2.52 per MMBTU of gas and $55.69 per barrel of oil. These are the average first-of-month prices for the prior 12-month period for Henry Hub gas and West Texas Intermediate (WTI) oil. Appropriate oil and gas pricing differentials, residue gas shrink, NGL yields, and NGL pricing as a fraction of WTI were calculated for each field using 12 months of revenue data where available.

Table 3 shows the average yearly price for the December 31, 2019 NYMEX strip used in the report.

TABLE 3

DECEMBER 31, 2019
NYMEX STRIP PRICE

YEAR	OIL $/BBL	GAS $/MMBTU
2020	58.83	2.294
2021	54.38	2.424
2022	52.09	2.420
2023	51.31	2.455
2024	51.44	2.492
AFTER	51.80	2.778

For the SEC price case, after applying appropriate differentials for each field, the weighted average realized product prices for 2020 were $54.24 per barrel of oil and $2.18 per MCF of gas, resulting in average 2020 differentials of negative $1.45 per barrel and negative $0.34 per MCF.

OPERATING COSTS

Future operating costs for each of the Contango wells are held constant at current values for the life of the property. These costs were calculated using 12-month lease operating expense (LOE) statements provided by Contango. In general, the LOE statements for each of the legacy properties were analyzed by field where available. For the Contango Legacy properties LOE data for the 12-month period ending June 30, 2019 was used to determine costs. The White Star and Will legacy properties had data available through September 2019. Using the statements provided each well was assigned a fixed monthly operating cost, variable costs for oil and gas, and water handling costs per produced barrel of water. Oil, gas, and NGL transportation and processing fees were also assigned.

In 2019 Contango analyzed LOE data and identified areas where operating cost reductions could be made. The LOE assignments for fixed and variable costs were reduced by amounts provided by Contango. These adjustments included reductions in equipment rental fees, headcount, and other costs. Additionally, cost estimates were increased in items where costs were expected to increase over the next year. These adjustments were implemented in the second quarter of 2019. LOE data provided for the second quarter of 2019 reflects a decrease of overall costs.

LOE data for the Eugene Island 11 properties was analyzed at a well level. Fixed operating costs were divided into three categories: producing well, non-producing well, and platform expenses. Non-producing wells are wells that are awaiting abandonment in 2020 and had costs attributable to insurance. Platform expenses include shared compression equipment rental and operating costs, pipeline costs, and other costs that were assigned to platform cost centers.

For the west Texas Delaware Basin properties, LOE was also analyzed at a well or cost center level. An additional water operating cost for shared water handling facilities was calculated and assigned per barrel of produced water.

CAPITAL COSTS

Capital expenditures to recomplete behind-pipe zones in existing wells, re-activate or work over existing wells, drill new wells, and install production facilities were provided by Contango and appear to be reasonable.

PROFESSIONAL GUIDELINES

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years, from known reservoirs under expected economic and operating conditions. Reserves are considered proved if economic productivity is supported by either actual production or conclusive formation tests.

Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves, but more certain to be recovered than possible reserves. Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

The reserve definitions used by Cobb & Associates are consistent with definitions set forth in the PRMS and approved by the Society of Petroleum Engineers and other professional organizations.

The reserves included in this report are estimates only and should not be construed as being exact quantities. Governmental policies, uncertainties of supply and demand, the prices actually received for the reserves, and the costs incurred in recovering such reserves, may vary from the price and cost assumptions in this report. Estimated reserves using price escalations may vary from values obtained using constant price scenarios. In any case, estimates of reserves, resources, and revenues may increase or decrease as a result of future operations.

Cobb & Associates has not examined titles to the appraised properties nor has the actual degree of interest owned been independently confirmed. The data used in this evaluation were obtained from Contango Oil & Gas Company and the non-confidential files of Cobb & Associates and were considered accurate.

We have not made a field examination of the Contango properties; therefore, operating ability and condition of the production equipment have not been considered. Also, environmental liabilities, if any, caused by Contango or any other operator have not been considered, nor has the cost to restore the property to acceptable conditions, as may be required by regulation, been taken into account.

In evaluating available information concerning this appraisal, Cobb & Associates has excluded from its consideration all matters as to which legal or accounting interpretation, rather than engineering, may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and conclusions necessarily represent only informed professional judgments.

William M. Cobb & Associates, Inc. is an independent consulting firm founded in 1983. Its compensation is not contingent on the results obtained or reported. Frank J. Marek, a Registered Texas Professional Engineer and a senior vice president of William M. Cobb & Associates, Inc., is primarily responsible for overseeing the preparation of the reserve report. His professional qualifications meet or exceed the qualifications of reserve estimators set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications include: Bachelor of Science degree in Petroleum Engineering from Texas A&M University 1977; member of the Society of Petroleum Engineers; member of the Society of Petroleum Evaluation Engineers; and 40 years of experience in estimating and evaluating reserve information and estimating and evaluating reserves.

Cobb & Associates appreciates the opportunity to be of service to you. If you have any questions regarding this report, please do not hesitate to contact us.

Sincerely,

WILLIAM M. COBB & ASSOCIATES, INC.
Texas Registered Engineering Firm F-84

Frank J. Marek, P.E.
President

STATE OF TEXAS
FRANK J. MAREK
52939
REGISTERED
PROFESSIONAL ENGINEER

Exhibit 99.2

W.D. Von Gonten&Co.
Petroleum Engineering
10496 Old Katy Road, Suite 200 Houston, Texas 77043 t 713.224.6333 f 713.224.6330 www.wdvgco.com

February 17, 2020

Mr. John P. Atwood
Senior Vice President
Exaro Energy III, LLC
5850 San Felipe, Suite 500
Houston, Texas 77057

Re: Engineering Evaluation
Estimate of Reserves & Revenues
Year End 2019 SEC Pricing
"As of" January 1, 2020

Dear Mr. Atwood:

At your request, W.D. Von Gonten & Co. has estimated future reserves and projected net revenues attributable to certain oil and gas interests currently owned by Exaro Energy III, LLC (Exaro). The properties represented herein are located in the Jonah field of Sublette County, Wyoming. A summary of the discounted future net revenue attributable to Exaro's Proven reserves, "As of" January 1, 2020, is as follows:

Year End 2019 SEC Pricing	Net to Exaro Energy III, LLC			
	Proved Developed Producing			Total Proved
	New Wells	Old Wells	Total	
Reserve Estimates				
Oil/Cond., Mbbl	290.8	318.0	608.7	608.7
Gas, MMcf	23,008.7	35,512.5	58,521.2	58,521.2
Gas Equivalent, MMcfe	24,753.3	37,420.2	62,173.6	62,173.6
Revenues				
Oil, $ (16.2)%	15,605,704	17,064,608	32,670,312	32,670,312
Gas, $ (83.8)%	61,856,584	107,752,000	169,608,576	169,608,576
Total, $	77,462,288	124,816,608	202,278,888	202,278,888
Expenditures				
AdValorem Taxes, $	3,435,224	6,019,844	9,455,069	9,455,069
Severance Taxes, $	3,586,504	6,315,720	9,902,224	9,902,224
Direct Operating Expense, $	22,293,802	47,084,896	69,378,704	69,378,704
Variable Operating Expense, $	17,077,705	26,529,832	43,607,538	43,607,538
Total, $	46,393,235	85,950,292	132,343,535	132,343,535
Investments				
Capital, $	1,631,483	4,508,666	6,140,149	6,140,149
Estimated Future Net Revenues(FNR)				
Undiscounted FNR, $	29,437,570	34,357,648	63,795,212	63,795,212
FNR Disc. @ 10%, $	17,692,578	23,767,958	41,460,536	41,460,536
Allocation Percentage by Classification				
FNR Disc. @ 10%, $	42.7%	57.3%	100.0%	

*Due to computer rounding, numbers in the above table may not sum exactly.

Report Preparation

Purpose of Report – The purpose of this report is to provide Exaro with a projection of future reserves and revenues attributable to certain Proved oil and gas interests presently owned.

Scope of Report – W.D. Von Gonten & Co. was engaged by Exaro to estimate the reserves and revenues associated with the properties included in this report. Once reserves were estimated, future revenue projections were generated utilizing SEC pricing guidelines.

Reporting Requirements – The Society of Petroleum Engineers (SPE) requires Reserves to be economically recoverable with prices and costs in effect on the "as of" date of the report. In conjunction with World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), and the European Associated of Geoscientists and Engineers (EAGE), the SPE has issued *Petroleum Resources Management System* (**2018 ed.**), which sets forth the definitions and requirements associated with the determination and classification of both Reserves and Resources. In addition, the SPE has issued *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information* (**2019 ed.**), which sets requirements for the qualifications and independence of qualified reserves evaluators and auditors.

Securities and Exchange Commission (SEC) Regulation S-K, Item 102 and Regulation S-X, Rule 4-10, and Financial Accounting Standards Board (FASB) Statement No. 69 requires oil and gas reserve information to be reported by publicly held companies as supplemental financial information. These regulations and standards provide for estimates of Proved reserves and revenues discounted at 10% and based on constant prices and costs.

The estimated Proved Reserves herein have been prepared in conformance with all SPE definitions and requirements in the above referenced publications.

Projections – The attached reserve and revenue projections are on a calendar year basis with the first time period being January 1 through December 31, 2020.

Property Discussion

Exaro signed an Earning and Development Agreement (EDA) with Encana Oil & Gas (Encana) in April 2012 that allowed them to gradually obtain increasing levels of ownership in the Jonah field. As part of the EDA, Exaro's interest in each well drilled prior to the April 2012 agreement (old Proved Developed Producing (PDP) wells) continued to increase as Encana drilled additional wells (new wells) within the field. Exaro's interest in the new wells stayed constant for the life of the well. For each new well drilled within the EDA, Exaro paid for 100% of the capital costs and earned 32.5% of Encana's interest in the new wellbore until Exaro was fully earned into their devoted interest. In addition, for each new well drilled, Exaro earned 0.40% interest in the old PDP wells and related leasehold if Encana's working interest in the new well location was 100% and a proportional share if not.

As of the date of this report, Encana has sold its ownership to Jonah Energy, LLC (Jonah Energy). Exaro notified Jonah Energy of its intent to terminate the EDA effective May 12, 2014, and thereafter participate under the existing Joint Operating Agreements (JOA's) going forward. Exaro currently has no locations left under the EDA. All wells are proposed under the JOA and Exaro has the right to participate for its working interest in each well. At the current time, there are no rigs running within Exaro's acreage.

Production in this area is primarily from the Lance sand which can range from 8,000' to 11,000' in depth and approach 3000' in interval thickness.

Beginning in 2014, Jonah Energy began drilling horizontal wells across the eastern sections of Exaro's acreage. To date, there are six horizontal wells currently producing.

Starting in February 2015, Jonah Energy began line pressure reduction projects in the field on varying groups of wells. They started by lowering the pressure from 200 psi to 50 psi in seventeen wells located in section 35. Lowering the pressure caused an increase in the production rate and reserves on most of the connected wells. Based on provided daily production data, W.D. Von Gonten & Co. was able to give these wells a brief uplift in the production projections. Jonah Energy has since begun and maintained several similar projects throughout Exaro's acreage.

Figure 1 displays the comparison of Exaro's historical monthly net production and W.D. Von Gonten & Co.'s forecasted net monthly production beginning January 1, 2020.

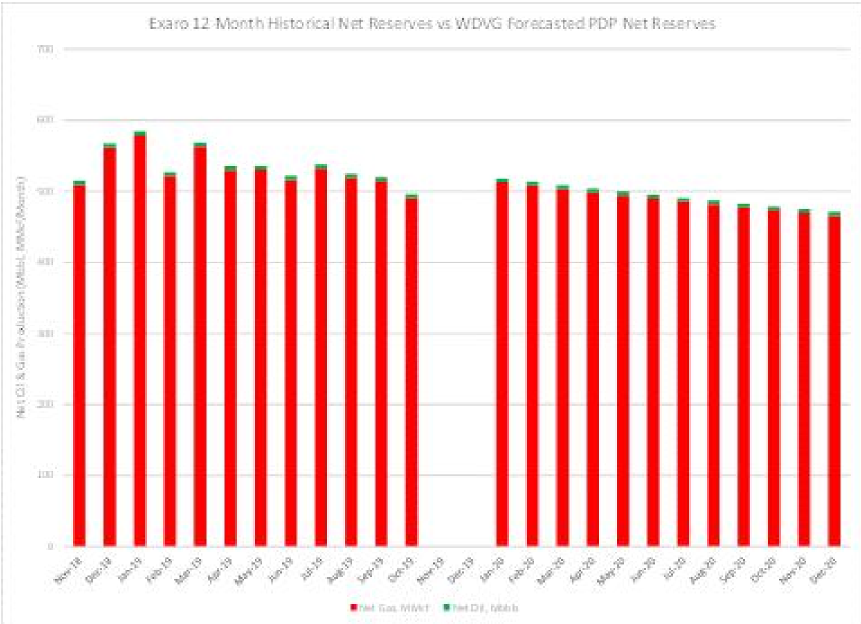

Figure 1: Historical Net Production and PDP Reserves Forecast as of January 1, 2020

Figure 2 below is a graphical comparison of Exaro's November 2018 through October 2019 historical net revenue and W.D. Von Gonten & Co.'s forecasted net revenue beginning January 1, 2020.

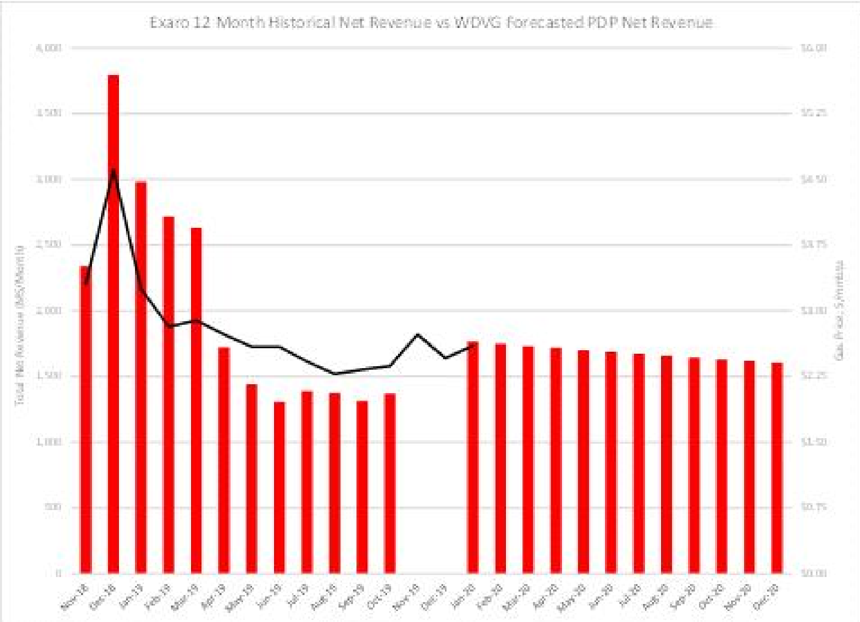

Figure 2: Historical Net Revenue and Forecasted Net Revenue as of January 1, 2020

Reserves Discussion

Reserves estimates represented herein were generally determined through the implementation of various methods including, but not limited to, performance decline, analogy, and type curve analysis. Based on the amount of available data, one or more of the above methods was utilized as deemed appropriate.

Reserves and schedules of production included in this report are only estimates. The amount of available data, reservoir and geological complexity, reservoir drive mechanism, and mechanical aspects can have a material effect on the accuracy of these reserve estimates. Due to inherent uncertainties in future production rates, commodity prices, and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom, and/or the actual costs incurred could be more or less than the estimated amounts.

Product Prices Discussion

SEC pricing is determined by averaging the first day of each month's closing price for the previous calendar year using published benchmark oil and gas prices. This method, as applied for the purposes of this report, renders a price of $55.65 per barrel of oil and $2.60 per MMBtu of gas. These prices were held constant throughout the life of the properties as per SEC guidelines.

Pricing differentials were applied on a field basis to reflect the actual prices received at the wellhead. Differentials typically account for transportation costs, geographical differentials, marketing bonuses or deductions, and any other factors that may affect the price actually received at the wellhead. W.D. Von Gonten & Co. determined the historical pricing differentials from lease operating data provided by Exaro representing the time period November 2018 through October 2019.

Figures 3 and 4 illustrate the comparison between historical differentials versus those projected.

Figure 3: Historical and Forecasted Oil Differential

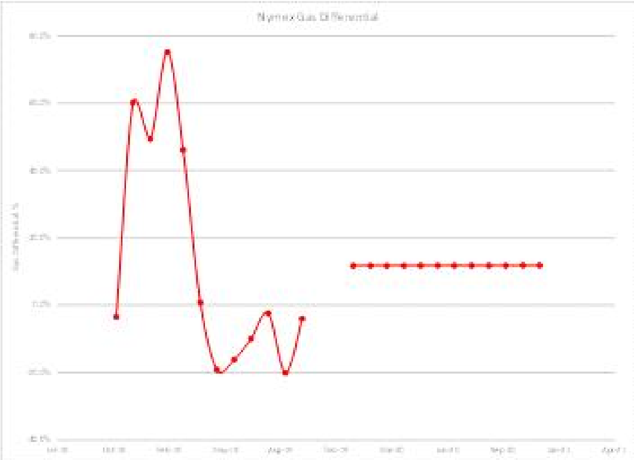

Figure 4: Historical and Forecasted Gas Differential

W.D. Von Gonten & Co. has included the historical NGL revenue and processing fees within the gas price differential for the new wells only. Due to existing and new contracts, the old wells do not include any NGL revenues or fees.

<u>Operating Expenses and Capital Costs Discussion</u>

Projected monthly operating expenses associated with the Jonah properties were based on the review of lease operating data provided by Exaro for the time period November 2018 through October 2019. Using the supplied data, W.D. Von Gonten & Co. applied a gross direct expense to each well on an individual basis. The horizontal wells have an increased monthly expense compared to vertical wells based on historical observations. A gross variable deduct of $0.48 per Mcf, which covers gathering fees, has been applied to all wells. In addition, a gross $3.84 per barrel salt water disposal (SWD) expense has been applied to each well. All direct and variable operating expenses were held constant for the economic life of each property.

Figure 5 below is a graphical comparison of historical net lease operating expenses for November 2018 through October 2019 versus comparable forecasted expenses for the subsequent twelve months.

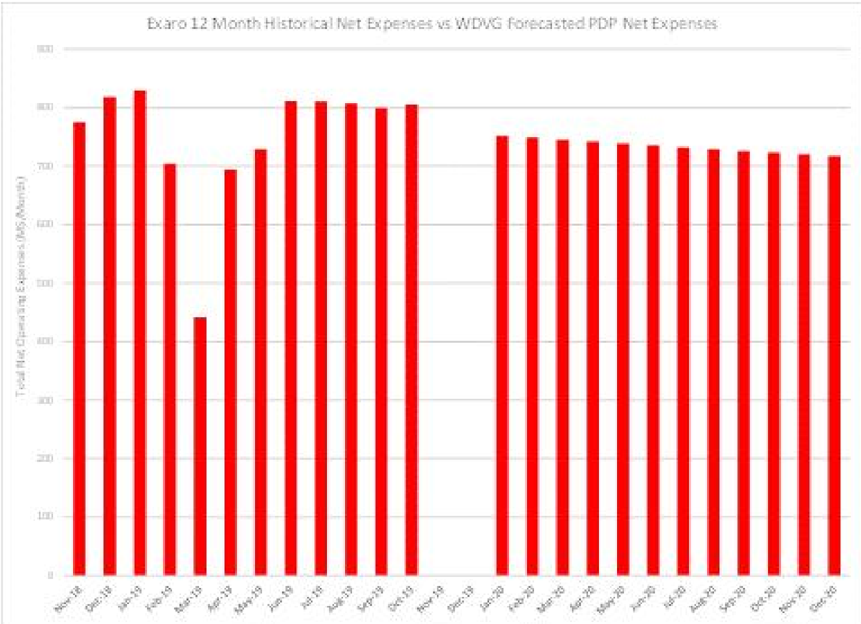

Figure 5: Historical and Forecasted Lease Operating Expense

There are no capital costs associated with any of the properties included herein. Currently, Exaro has no knowledge of anticipated work efforts scheduled by the operator.

<u>Other Considerations</u>

<u>Abandonment Costs</u> – Cost estimates regarding future plugging and abandonment liabilities associated with these properties were supplied by Exaro for the purposes of this report. As we have not inspected the properties personally, W.D. Von Gonten & Co. expresses no warranties as to the accuracy or reasonableness of these assumptions. A third party study would be necessary in order to accurately estimate all future abandonment liabilities.

<u>Data Sources</u> – Data furnished by Exaro included basic well information, lease operating statements, ownership, pricing, and production information on certain leases. IHS Energy archives was utilized to view the monthly production for some of the wells included in this report.

<u>Context</u> – We specifically advise that any particular reserve estimate for a specific property not be used out of context with the overall report. ***The revenues and present worth of future net revenues are not represented to be market value either for individual properties or on a total property basis.***

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the January 1, 2020 estimated oil and gas volumes. The reserves in this report can be produced under current regulatory guidelines. Actual future commodity prices may differ substantially from the utilized pricing scenario which may or may not extend or limit the estimated reserves and revenue quantities presented in this report.

We have not inspected the properties included in this report, nor have we conducted independent well tests. W.D. Von Gonten & Co. and our employees have no direct ownership in any of the properties included in this report. Our fees are based on hourly expenses, and are not related to the reserve and revenue estimates produced in this report. The responsible technical personnel referenced below have obtained the qualifications and meet the requirements of objectivity for Qualified Reserves Evaluator employed internally by W.D. Von Gonten & Co. as set forth in the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information* (**2019 ed.**) promulgated by the SPE.

Thank you for the opportunity to assist Exaro Energy III, LLC with this project.

STATE OF TEXAS
PHILLIP R. HUNTER
96590
LICENSED
PROFESSIONAL ENGINEER

W.D. Von Gonten&Co.
Petroleum Engineering
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Respectfully submitted,

Phillip R. Hunter

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Jamie Foster

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Reviewed by:

W.D. Von Gonten Jr.

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