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, 2017

☐ **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)

Delaware	**95-4079863**
(State or other jurisdiction of incorporation or organization)	(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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☐ (Do not check if smaller reporting company)	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 30, 2017, 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 $129.5 million. As of March 5, 2018, there were 25,479,438 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, 2017
TABLE OF CONTENTS

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, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases “should be”, “will be”, “believe”, “expect”, “anticipate”, “estimate”, “forecast”, “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:

- our ability to successfully develop our undeveloped acreage in the Southern Delaware Basin, integrate the operations relating thereto with our existing operations and realize the benefits associated therewith;
- our financial position;
- our business strategy, including outsourcing;
- meeting our forecasts and budgets;
- expectations regarding natural gas and oil markets in the United States;
- volatility in natural gas, natural gas liquids and oil 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;
- 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;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations, and fund our drilling program;
- the cost and availability of rigs and other materials, services, and operating equipment;
- timely and full receipt of sale proceeds from the sale of our production;
- the ability to find, acquire, market, develop and produce new natural gas and oil properties;
- interest rate volatility;
- 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);
- worldwide economic conditions;
- 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; and
- ability to obtain adequate insurance coverage on commercially reasonable terms.

Any of these factors and other factors contained 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, 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. All forward-looking statements 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 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. 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 properties in Texas and Wyoming and to use that cash flow to explore, develop, exploit, increase production from and acquire crude oil and natural gas properties in onshore West Texas, the Texas Gulf Coast and the Rocky Mountain regions of the United States.

The following table lists our primary producing areas as of December 31, 2017:

Location	Formation
Gulf of Mexico	Offshore Louisiana - water depths less than 300 feet
Madison and Grimes counties, Texas	Woodbine (Upper Lewisville)
Pecos County, Texas	Southern Delaware Basin (Wolfcamp)
Other Texas Gulf Coast	Conventional and smaller unconventional formations
Zavala and Dimmit counties, Texas	Buda / Austin Chalk
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.

Since October 2013, upon the merger with Crimson Exploration Inc. ("Crimson") (the "Merger"), and prior to the decline in crude oil and natural gas prices in 2015, we focused our drilling efforts on liquids-rich horizontal resource plays. Beginning in the second half of 2015, we reduced our drilling program in response to the challenging commodity price environment, and instead focused on: (i) the preservation of our strong and flexible financial position, including limiting our overall capital expenditure budget; (ii) the identification of opportunities for cost and production efficiencies in all areas of our operations; and (iii) the maintenance of core leases and the continued identification of new resource potential opportunities. As a result, until the latter half of 2016, our only drilling activity was in Weston County, Wyoming, where we completed our third well targeting the Muddy Sandstone formation. During the third quarter of 2016, we acquired a 12,100 gross acre position (5,000 net) in the Southern Delaware Basin in Pecos County, Texas (the "Acquisition"), and as of December 31, 2017, had increased our acreage in the Southern Delaware Basin to 16,500 gross acres (6,800 net). Since the Acquisition, we have begun production from seven wells in the Southern Delaware Basin and are waiting on completion of an eighth well. We currently expect that the Southern Delaware Basin position will continue to be the primary focus of our drilling program for 2018.

In addition to our above producing properties, we also have (i) operated producing properties in the Haynesville Shale, Mid Bossier Shale and the James Lime formations in East Texas and (ii) operated conventional producing properties in the south and southeast areas of Texas. In December 2016, we sold our operated producing properties in the Denver Julesburg Basin ("DJ Basin") in Weld and Adams counties in Colorado.

During the quarter ended September 30, 2016, in conjunction with the Acquisition, we completed an underwritten public offering of 5,360,000 shares of our common stock for net proceeds of approximately $50.5 million, which were used to fund the initial purchase of this acreage and provide funding for the costs associated with drilling our initial wells in the Southern Delaware Basin.

Our production for the year ended December 31, 2017 was approximately 20.1 Bcfe (or 55.1 Mmcfe/d), was 68% from our offshore properties and was 69% natural gas. Our production for the three months ended December 31, 2017 was approximately 4.8 Bcfe (or 51.8 Mmcfe/d), was 66% from our offshore properties and was 68% natural gas. As of December 31, 2017, our proved reserves were approximately 65% proved developed, were 40% offshore, were 48% natural gas and were 98% attributed to wells and properties operated by us.

As of December 31, 2017, our proved reserves, as estimated by Netherland, Sewell & Associates, Inc. ("NSAI") and William M. Cobb and Associates ("Cobb"), our independent petroleum engineering firms, in accordance with reserve reporting guidelines required by the Securities and Exchange Commission ("SEC"), were approximately 189.3 Bcfe, consisting of 91.7 Bcf of natural gas, 10.6 MMBbl of crude oil and condensate and 5.6 MMBbl of natural gas liquids ("NGLs"), with a present value, discounted at a 10% rate (PV-10), of $257.3 million, and a Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") of $255.9 million. PV-10 as of December 31, 2017 was based on adjusted prices of $2.92 per MMbtu of natural gas, $47.41 per barrel of oil, and $18.59 per barrel of NGLs. 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, 2017 (excluding reserves attributable to our investment in Exaro), as estimated by NSAI and Cobb, and our net average daily production for the year ended December 31, 2017:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	Natural % Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Offshore GOM	75.4	3 %	82 %	15 %	100 %	37.7
Southeast Texas	30.9	41 %	37 %	22 %	63 %	8.0
South Texas	25.7	46 %	40 %	14 %	64 %	5.6
West Texas	55.5	64 %	15 %	21 %	19 %	2.6
Other (1)	1.8	65 %	32 %	3 %	100 %	1.2
Total	189.3					55.1

(1) Includes East Texas, Mississippi, Louisiana and Wyoming.

The following summary table sets forth certain information with respect to the proved reserves attributable to our investment in Exaro, as of December 31, 2017, 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, 2017:

Region	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Investment in Exaro	30.7	6 %	94 %	— %	99 %	26.4

Our Strategy

Our long-term business strategy is:

• *Enhancing our portfolio by dedicating the majority of our drilling capital to our 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. For the foreseeable future, we will focus our drilling capital on the Southern Delaware Basin position, as we believe it provides excellent returns in the current oil price environment. We believe we possess the flexibility to focus on the development of our Southern Delaware Basin potential without jeopardizing our acreage position in other areas, as the vast majority of our acreage in those other areas is held by production or has longer term lease terms.

• *Pursuing accretive, opportunistic acquisitions that meet our strategic and financial objectives.* We intend to evaluate opportunistic acquisitions of crude oil and natural gas properties, both undeveloped and developed, in areas where we currently have a presence and/or specific operating expertise, and to pursue undeveloped acreage positions, at reasonable cost, in new areas that we believe to be complementary to our existing plays and feel have significant exploration, exploitation or operational upside. We believe that the ongoing low commodity price environment might provide growth opportunities for us through potential corporate combinations.

• *Selectively exploiting, in a higher commodity price environment, our existing onshore producing conventional natural gas property portfolio to generate additional cash flows.* We believe our multi-year drilling inventory of exploitation opportunities on our existing onshore conventional natural gas oriented producing properties provides us with a solid, dependable platform for future reserve and production growth. We will continuously monitor the commodity price environment and technical advancements, and if warranted, make adjustments to our investment strategy.

We currently expect to focus our 2018 capital program on our Southern Delaware Basin acreage, which is expected to continue to generate positive returns on our drilling investment in the current price environment. Assuming results are as expected, and market conditions remain favorable, we will proceed to drill throughout the year. Until a sustained improvement in commodity prices occurs, we do not currently expect to devote meaningful capital to our other areas, but will devote capital to those areas to fulfill leasehold commitments, preserve core acreage and, where determined appropriate to do so, expand our presence in those existing areas. We will continue to make balance sheet strength a priority in 2018 by limiting capital expenditures to a level that can be funded through internally generated cash flow and non-core asset sales. We will continue to evaluate new organic opportunities for growth and will continue to evaluate pursuing stressed or distressed 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 continue to 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 2018 capital expenditure budget is initially expected to include the following:

- Pecos County, Texas – We forecast capital expenditures of approximately $52 million for drilling in this area.
- Other – We forecast capital expenditures of approximately $2 million for unproved leasehold acquisition costs.

Properties

Offshore Gulf of Mexico

As of December 31, 2017, our offshore assets consisted of six federal and five state of Louisiana company-operated wells in the shallow waters of the GOM. These 11 wells are located in two fields. The following summary table sets forth certain information with respect to our offshore reserves as of December 31, 2017 and average daily offshore production for the year ended December 31, 2017:

Field	Estimated Proved Reserves (Bcfe)	% Crude Oil / Condensate	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mmcfe/d)
Dutch and Mary Rose	72.0	3 %	81 %	16 %	100 %	33.7
Vermilion 170	3.4	4 %	84 %	12 %	100 %	3.8
South Timbalier 17	—	— %	— %	— %	— %	0.2
Total	75.4					37.7

Dutch and Mary Rose Field

We operate five wells located in federal waters at Eugene Island 10 (“Dutch”), and five wells located in adjacent Louisiana state waters (“Mary Rose”). 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 gas markets thereby minimizing downtime risk and providing the ability to select the best sales price for our 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 at Burns Point, Louisiana. We have recently completed a 6” oil pipeline to third-party owned and operated onshore processing facilities in St. Mary Parish, Louisiana, providing us with two separate oil markets. Production facilities include a turbine type compressor capable of servicing all ten Dutch and Mary Rose wells at the Eugene Island 11 platform. Condensate can also flow to onshore markets and multiple refineries.

Vermilion 170 Field

We own and operate one well located in federal waters with a dedicated production facility at Vermilion 170. Production from this platform, which includes compression equipment, flows via the Sea Robin Pipeline to a third-party owned and operated onshore processing plant.

Other Offshore

Our Ship Shoal 263 field, located in federal waters, and South Timbalier 17 field, located in Louisiana state waters, were historically included in "Other Offshore". During 2017, the Ship Shoal field was permanently plugged and abandoned, and the production facilities were removed and sold. In late 2017, the South Timbalier well was permanently plugged and abandoned, and the production facilities were removed.

Onshore Properties

Southern Delaware Basin

Since the closing of the Acquisition in late July 2016, we and our partner have increased our leasehold footprint to approximately 6,800 acres, net to Contango. As of December 31, 2017, we currently estimate that we have proven reserves of 55.5 Bcfe and close to 400 gross drilling locations, initially targeting the Wolfcamp A, Wolfcamp B and Second Bone Spring formations. Substantially all of the locations can accommodate 10,000 foot laterals. As previously disclosed, during 2017 we brought our first four Southern Delaware Basin wells on production (two in the Upper Wolfcamp A, one in the Middle Wolfcamp A, and one in the Lower Wolfcamp A), with an average maximum 30 day initial production rate ("IP") of 968 Boed (72% oil).

In mid-December 2017, we brought our fifth horizontal well on production, the Crusader #1H, targeting the Lower Wolfcamp A. This well was drilled to a total measured depth ("TMD") of 20,275 feet, including a 10,184 foot lateral, and was completed with 50 stages of fracture stimulation, reaching a 30-day average IP of 389 Boed (67% oil). Our sixth well, the Ragin Bull #3H, targeting the Lower Wolfcamp A, was spud in November 2017. This well was drilled to a TMD of 20,570 feet, including a 10,325 foot lateral, and was completed with 50 stages of fracture stimulation. Production began in January 2018, and the well reached a 30-day average IP of 716 Boed (67% oil).

Our seventh well, the River Rattler #1H, our first Wolfcamp B test, was spud in December 2017. This well was drilled to a TMD of 20,710 feet, including a 10,275 foot lateral, and was completed with 50 stages of fracture stimulation. Production is expected to begin in mid-March 2018. We continue to identify cost efficiencies in our drilling efforts, as evidenced by the fact that the Ragin Bull #3H and River Rattler #1H have been our most efficient wells to date, taking only 27 days from spud to TMD.

Our eighth well, the Ragin Bull #2H, our second Wolfcamp B test, was spud in January 2018. This well was drilled to a TMD of 20,624 feet, including a 10,344 foot lateral, and is currently waiting on completion with 50 stages of fracture stimulation. There have been multiple Wolfcamp B wells adjacent to our leasehold that have been put on production recently by our offset operators, thereby derisking the Wolfcamp B in the area and providing encouragement for the development of that formation on our acreage.

Southeast Texas (Woodbine)

As of December 31, 2017, our Southeast Texas region included approximately 29,300 gross (17,100 net) acres, proven reserves of 30.9 Bcfe, and 81 gross (45 net) producing wells. No drilling capital was allocated to this area in 2016 or 2017 due to the low commodity price environment. For 2018, our current budget does not anticipate further drilling in this area, but should we experience sustained improvement in commodity prices, we could increase our activity. We currently have approximately 12,100 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.

South Texas (Buda/Eagle Ford)

As of December 31, 2017, our South Texas region included approximately 89,600 gross (40,800 net) acres, proven reserves of 25.7 Bcfe, and 217 gross (96.5 net) producing wells. We believe approximately 16,700 gross (7,800 net) acres to be prospective for the Buda and Eagle Ford Shale plays. No drilling activity has been conducted in this area since 2014 due to the reduction in our capital expenditure programs in response to the commodity price environment. We do not anticipate devoting any drilling capital to this area in 2018.

Our estimated net proven Buda/Eagle Ford reserves in this area were 12.2 Bcfe, comprised of 94% liquids, with 41 gross (17.6 net) producing wells, as of December 31, 2017.

South Texas (Elm Hill Project)

As of December 31, 2017, we held approximately 4,900 gross acres (2,700 net) in Fayette, Gonzales, Caldwell and Bastrop counties, Texas. There was no drilling activity in 2016 or 2017, and we recognized an impairment expense of $6.8 million for the year ended December 31, 2016. The Company and its partner have no plans to further test this area.

The remaining 68,000 gross (30,300 net) acres in our South Texas region are located in our conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved conventional reserves in this region were 12.1 Bcfe, comprised of 71% gas, with 176 gross (78.9 net) producing wells, as of December 31, 2017.

Weston County, Wyoming (N. Cheyenne Project)

In 2015, we began drilling the first of three successful wells in this area targeting the Muddy Sandstone formation. Based on current results, a sustained improvement in oil prices will be needed to justify allocation of drilling capital to this area compared to our Southern Delaware Basin position. As a result of drilling these wells, we have satisfied the right to earn 35,000 net acres (approximately 4% of which is held by production).

Natrona County, Wyoming (FRAMS Project)

We spud our first well targeting the Mowry Shale in 2015, which proved to be unsuccessful. As a result, we recognized $6.7 million in exploration expenses for the cost of drilling the well for the year ended December 31, 2016 and $2.9 million in impairment expense in 2016 related to our unproved acreage in Natrona County, Wyoming. No drilling activity was conducted in this area in 2017.

Other (East Texas)

As of December 31, 2017, our East Texas region included approximately 6,000 gross (3,600 net) acres primarily in San Augustine County, with proven reserves of 0.5 Bcfe comprised of 90% gas, and 10 gross (5.1 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. We will continue to monitor that activity and results; however, we do not anticipate devoting any capital to this area during 2018. As of December 31, 2017, substantially all of our acreage in our East Texas region was held by production.

Other (Colorado)

On December 30, 2016, we completed the sale of all of our Colorado assets to an independent oil and gas company for an aggregate purchase price of $5.0 million, subject to normal post-closing adjustments. The properties sold consisted of approximately 16,000 gross (11,200 net) acres and associated producing vertical wells primarily in Adams and Weld counties. At the time of sale, the sold properties had proved reserves of 4.2 Bcfe and during 2016 average net daily production was 0.4 Mmcfe/d.

Other

As of December 31, 2017, we held approximately 8,300 gross (6,000 net) mostly undeveloped acres in Louisiana, Mississippi, and North Texas.

Impairment of Long-Lived Assets

We recognized approximately $1.8 million in non-cash impairment charges in 2017. Under US GAAP, an impairment charge is required when the unamortized capital cost of any individual property within the Company’s proved property base exceeds the risked estimated future net cash flows from the proved, probable and possible reserves for that property. Included in the impairment charge for the year is approximately $0.3 million related to proved property impairment for our Tuscaloosa Marine Shale ("TMS") properties, a shale play in central Louisiana and Mississippi, due to revised estimated reserves. The 2017 impairment charges also consist of $1.5 million related to the partial impairment of two unused offshore platforms in onshore storage.

If oil and/or natural gas prices decline from prices at December 31, 2017, 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, 2017, we had invested approximately $46.9 million in Exaro, with no anticipation of making any additional equity contributions, as our commitment to invest 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 for our consolidated results.

As of December 31, 2017, Exaro had 645 wells on production over its 5,760 gross acres (1,040 net acres), with a working interest between 2.4% and 32.5%. These wells were producing at a rate of approximately 26 Mmcfe/d, net to Exaro. The operator of these interests has applied for multiple drilling permits for horizontal wells that will be located on parts of our acreage. Exaro's working interest in the drilling spacing units for the applied for horizontal wells ranges from 1% to 6%. As of December 31, 2017, the operator has been approved to drill two horizontal wells, in which Exaro has a net working interest of 2.4%. For the year ended December 31, 2017, the Company recognized a net investment gain of approximately $2.7 million, net of no tax expense, as a result of its investment in Exaro. As of December 31, 2017, reserves attributable to our investment in Exaro were 30.7 Bcfe. See Note 10 to our Financial Statements - "Investment in Exaro Energy III LLC" for additional details related to this 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 crude oil properties to secure our senior secured revolving credit facility. 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 12 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 crude 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 crude 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 crude 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.

As of December 31, 2017, we had the following derivative contracts in place with members of our bank group:

Commodity	Period	Derivative	Volume/Month		Price/Unit
Natural Gas	Jan 2018 - July 2018	Swap	370,000 MMBtus	$	3.07 (1)
Natural Gas	Aug 2018 - Oct 2018	Swap	70,000 MMBtus	$	3.07 (1)
Natural Gas	Nov 2018 - Dec 2018	Swap	320,000 MMBtus	$	3.07 (1)
Oil	Jan 2018 - June 2018	Swap	20,000 Bbls	$	56.40 (2)
Oil	July 2018 - Oct 2018	Collar	20,000 Bbls	$	52.00 - 56.85 (2)
Oil	Nov 2018 - Dec 2018	Collar	15,000 Bbls	$	52.00 - 56.85 (2)
Oil	Jan 2018 - Dec 2018	Collar	2,000 Bbls	$	52.00 - 58.76 (3)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$	50.00 - 58.00 (2)

In January 2018, we entered into the following additional derivative contracts with members of our bank group:

Commodity	Period	Derivative	Volume/Month		Price/Unit
Oil	Jan 2018 - July 2018	Collar	6,000 Bbls	$	58.00 - 68.00 (2)
Oil	Nov 2018 - Dec 2018	Collar	5,000 Bbls	$	58.00 - 68.00 (2)
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$	52.00 - 59.45 (3)

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

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

(3) Based on West Texas Intermediate crude oil prices.

Decreases in commodity prices would adversely affect our revenues, profits and the value of our proved reserves. Historically, the prices received for natural gas and oil have fluctuated widely. Among the factors that can cause these fluctuations are:

- The domestic and foreign supply of natural gas and oil.
- Overall economic conditions.
- The level of consumer product demand.
- Adverse weather conditions and natural disasters.
- The price and availability of competitive fuels such as heating oil and coal.
- Political conditions in the Middle East and other natural gas and oil producing regions.
- The level of LNG imports/exports.
- Domestic and foreign governmental regulations.
- Special taxes on production.
- The loss of tax credits and deductions.

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, 2017, calculated on an equivalent basis, was ConocoPhillips Company (51.2%). 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 crude oil we produce. There is also competition between producers of natural gas and crude 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 crude 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 crude oil, natural gas and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of crude 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 crude 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 crude oil, natural gas and natural gas liquids, protect rights to produce crude oil, natural gas and natural gas liquids between owners in a common reservoir, control the amount of crude 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 Crude 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 crude 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 crude 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 crude 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 futures energy commodities market 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 $1.12 million per day 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 crude 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 crude oil and natural gas liquids transportation rates may tend to increase the cost of transporting crude 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 crude oil production from our crude 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 crude 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 or restrictions in permitting or performance of projects and the issuance of orders enjoining some or all of our operations in affected areas. Public interest in the protection of the environment has increased dramatically in recent years. The trend in environmental legislation and regulations in recent years has been to place more restrictions and limitations on activities that may affect the environment, which is expected to result in increased costs of doing business and consequently affect profitability.

The 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 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 crude 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. For example, following in response to the filing of a lawsuit by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the U.S. District Court for the District of Columbia in December 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. 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 Clean Air Act, as amended (the "CAA"), and comparable state laws restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and 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 crude 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.

Based on findings made by the EPA that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA adopted regulations under 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 or delay our ability to obtain air permits for new or modified sources. In addition, 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 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 are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Moreover, in December 2015, the United States joined other countries of the United Nations in preparing an agreement requiring member countries to review and establish goals for limiting GHG emissions. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions but, rather, includes pledges to voluntarily limit or reduce future emissions. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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.

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. The disposal of oil and natural gas wastes into underground injection wells are subject to the Safe Drinking Water Act, as amended (the "SDWA"), and analogous state laws. 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 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, 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. 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 Oil Pollution Act of 1990 (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. 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. In addition, in January 2018, the federal Bureau of Ocean Energy Management ("BOEM") has raised OPA's damages liability cap to $137.7 million. 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. In addition, 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 the Company's offshore lease operations affect state waters, the Company 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 crude 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 stimulate production. 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. 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 under certain circumstances.

Congress has from time to time considered, but not enacted, legislation to provide for federal regulation 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 delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. 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.

Environmental laws such as the Endangered Species Act, as amended ("ESA"), may impact exploration, development and production activities on public or private lands. The 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. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. 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, time delays or limitations on our drilling program activities, which costs delays or limitation 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.

In recent years, the BOEM and the BSEE, each agencies of the U.S. Department of the Interior, have imposed more stringent permitting procedures and regulatory safety and performance requirements for wells in federal waters. In addition, 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 or delay new drilling and ongoing development efforts. In addition, new regulatory initiatives may be adopted or enforced by the BOEM or the BSEE in the future that could result in additional costs, delays, restrictions or obligations with respect to oil and natural gas exploration and production operations conducted offshore. Any new rules, regulations or legal initiatives could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding requirements and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities. 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. For example, in April 2016, the BOEM published a proposed rule that would update existing air-emissions requirements relating to offshore oil and natural gas activity on the OCS. Additionally, the BOEM issued a Notice to Lessees and Operators (the “NTL #2016-N01”) that became effective in September 2016 and bolsters supplemental bonding procedures for the decommissioning of offshore wells, platforms, pipelines and other facilities. 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 one or more 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 could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit 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 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 of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, 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.

During 2017, however, with the issuance of Order 3350 in May 2017 by U.S. Department of the Interior Secretary Ryan Zinke that directed the BOEM and the BSEE to reconsider a number of regulatory initiatives governing oil and natural gas exploration, development and production activities on the OCS ("Order 3350"), the BSEE and the BOEM have been directed to reconsider a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities, including, for example, NTL #2016-N01 and the rules relating to blow-out preventers and well control, and provide recommendations on whether such regulatory initiatives should continue to be implemented. Moreover, Order 3350 directed the BOEM to immediately cease all activities to promulgate the April 2016 proposed rule relating to offshore air quality control. One consequence of this review is that on December 29, 2017, the BSEE published proposed revisions to its regulations regarding offshore drilling safety equipment, which proposal includes the removal of the requirement 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. The December 2017 proposed rule has not been finalized, and there remains substantial uncertainty as to the scope and extent of any revisions to existing oil and gas safety and performance-related regulations and other regulatory initiatives that ultimately will be adopted by the BSEE and the BOEM pursuant to those agencies' review process.

See "Item 1A. Risk Factors" for further discussion on hydraulic fracturing; ozone standards; climate change, including methane or other greenhouse gas emissions; releases of regulated substances; and other aspects of compliance with legal or financial assurance requirements or relating to environmental protection, including with respect to offshore leases.

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 onshore lands and offshore tracts in 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. While we do not meet the requirements for self-insurance, we estimated the impact of the requirement to provide additional security under NTL #2016-N01 for our operations in the Gulf of Mexico and do not believe that the revised policy will have a material impact on our operations in the Gulf of Mexico.

During 2017, however, with the issuance of Order 3350, the BSEE and the BOEM have been directed to reconsider a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities, including, for example, NTL #2016-N01. Consequently, during 2017, 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 sole 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 sole liabilities. 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. 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.

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 an operating committee of 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 require a shut-in our Gulf of Mexico operations if not resolved within the required time.

Employees

On December 31, 2017, we had 63 full time employees, of which 20 were field personnel. 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 corporate offices are located at 717 Texas Avenue in downtown Houston, Texas, under a lease that expires March 31, 2019. Rent, including parking, related to this office space for the year ended December 31, 2017 was approximately $2.2 million. As of January 2017, a portion of our space in the building is being subleased through the lease expiration date for $0.5 million annually.

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. Our Code of Conduct is available on the Company's website at www.contango.com. Any shareholder who so requests may obtain a copy of the Code of Conduct by submitting a request to the Company's corporate secretary at the address on the cover of this Form 10-K. 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 five 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 on Form 10-K.

Available Information

You may read and copy all or any portion of this report on Form 10-K, our quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, without charge at the office of the Securities and Exchange Commission (the "SEC") in Public Reference Room, 100 F Street NE, Washington, DC, 20549. Information regarding the operation of the public reference rooms may be obtained by calling the SEC at 1-800-SEC-0330. In addition, 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.

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. An investment in the Company is subject to risks inherent in our business. 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.

RISK FACTORS RELATING TO OUR BUSINESS

We have no ability to control the market price for natural gas and oil. Natural gas 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 the business, the results of operations and financial condition of the Company.

Our revenues, profitability and future growth depend significantly on natural gas and crude oil prices. Natural gas and crude oil prices remained relatively low through 2017. While natural gas prices have remained consistent with 2017 levels, crude oil prices increased slightly during the final months of 2017 and throughout early 2018. The markets for these commodities are volatile and prices received affect the amount of future cash flow available for capital expenditures and repayment of indebtedness and our ability to raise additional capital. Lower prices also affect the amount of natural gas and oil that we can economically produce. Factors that can cause price fluctuations include:

- Overall economic conditions, domestic and global.
- The domestic and foreign supply of natural gas and oil.
- The level of consumer product demand.
- Adverse weather conditions and natural disasters.
- The price and availability of competitive fuels such as LNG, heating oil and coal.
- Political conditions in the Middle East and other natural gas and oil producing regions.
- The ability of the members of the Organization of Petroleum Exporting Countries and other oil exporting nations to agree to and maintain oil price and production controls.
- The level of LNG imports and any LNG exports.
- The level of natural gas exports.
- Domestic and foreign governmental regulations.
- Special taxes on production.
- Access to pipelines and gas processing plants.
- The loss of tax credits and deductions.

A substantial or extended decline in natural gas and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas 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 exposure to potential declines in commodity prices, however, these derivative contracts may not be sufficient to mitigate the effect of lower commodity prices.

Part of our strategy involves drilling in new or emerging plays; therefore, our drilling results in these areas are not certain.

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 crude oil, natural gas and natural gas liquids price declines. To the extent we are unable to execute our expected drilling program in these areas, our return on investment may not be as attractive as we anticipate and our common stock price may decrease. 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.

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 future cash flows are subject to a number of variables, including the level of production from existing wells. 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. As a result, we generally must locate and develop or acquire new crude oil or natural gas reserves to offset declines in these initial production rates. If we are unable to do so, these declines in initial production rates may result in a decrease in our overall production and revenue over time.

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 crude oil, natural gas and natural gas liquids 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 crude oil, natural gas and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations, borrowings under our senior secured revolving credit agreement and/or proceeds from non-core asset sales. Our cash flow from operations and access to capital is subject to a number of variables, including:

- Our proved reserves.
- The level of crude oil, natural gas and natural gas liquids we are able to produce from existing wells.
- The prices at which crude 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 crude oil, natural gas and natural gas liquids 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 agreements contain 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 senior secured revolving credit agreement, we may be unable to obtain financing otherwise currently available under our senior secured revolving credit agreement. As part of the regular redetermination schedule, the borrowing base on our revolving credit agreement was redetermined at $115 million effective November 9, 2017 and through May 01, 2018. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity.”

In addition, 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. For example, at December 31, 2017, we were not in compliance with the Current Ratio covenant under our credit agreement, although we obtained a waiver for such non-compliance. Any future failure to comply with these covenants could result in an event of default under such indebtedness and the potential foreclosure on the collateral securing such debt, and could cause a cross-default under any of our other outstanding indebtedness.

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 generally 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 crude 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.

Natural gas and crude oil prices remained relatively low through most of 2017, and while natural gas prices have remained consistent with 2017 levels, crude oil prices increased slightly during the final months of 2017 and throughout early 2018. An extended or more severe downturn could have material adverse effects on the liquidity of our working interest partners. 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 and derivative counterparties, and any material nonpayment or nonperformance by our customers 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, which risks may increase during periods of economic uncertainty. Furthermore, some of our customers 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 is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. 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 additional wells.

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. 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. Further, 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 crude 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.

Approximately 35% of our total estimated proved reserves at December 31, 2017 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 crude 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 crude 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 crude 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, 2017 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2017. For our condensate and natural gas liquids, the average West Texas Intermediate (Cushing) posted price was $51.34 per barrel for offshore and onshore Southern Delaware Basin volumes, as prepared by Cobb, and the average West Texas Intermediate (Plains) posted price was $47.79 per barrel for all other onshore volumes, as prepared by NSAI. For our natural gas, the average Henry Hub spot price was $2.98 per MMBtu for all offshore and onshore volumes, as prepared by both Cobb and NSAI. Assuming strip pricing as of March 1, 2018 through 2022 and keeping pricing flat thereafter, instead of 2017 SEC pricing, while leaving all other parameters unchanged, the Company's proved reserves would have been 188.6 Bcfe and the PV-10 value of proved reserves would have been $258.3 million. Any adjustments to the estimates of proved reserves or decreases in the price of crude oil or natural gas may decrease the value of our common stock. A reconciliation of our Standardized Measure to PV-10 is provided under "Item 2. Properties – PV-10".

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 crude 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. For example, we have over 4,000 square miles of 3D data in the South Texas and Gulf Coast regions. 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. 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 crude 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 crude 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;

- pressures;
- fires;
- explosions and blowouts;
- pipe or cement failures;
- 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;
- unexpected operational events;
- shortages of skilled personnel;
- 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, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume 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 crude 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 crude 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.

The natural gas and oil business involves many operating risks that can cause substantial losses and our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The natural gas and oil business involves a variety of operating risks, including:

- Blowouts, fires and explosions.
- Surface cratering.
- Uncontrollable flows of underground natural gas, oil or formation water.
- Natural disasters.
- Pipe and cement failures.
- Casing collapses.
- Stuck drilling and service tools.
- Reservoir compaction.
- Abnormal pressure formations.
- Environmental hazards such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures or unauthorized discharges of brine, toxic gases, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment.
- Capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which we have no control.
- Repeated shut-ins of our well bores could significantly damage our well bores.
- Required workovers of existing wells that may not be successful.

If any of the above events occur, we could incur substantial losses as a result of:

- Injury or loss of life.
- Reservoir damage.
- Severe damage to and destruction of property or equipment.
- Pollution and other environmental and natural resources damage.
- Restoration, decommissioning or clean-up responsibilities.
- Regulatory investigations and penalties.
- Suspension of our operations or repairs necessary to resume operations.

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. For example, our total production for the year ended December 31, 2017 declined by 0.4 Mmcfe/d as a result of downtime associated with the impact of Hurricane Harvey. 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.

If we were to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect our ability to conduct operations. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. We may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

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 of crude oil, natural gas and natural gas liquids, as well as interest rates, we have, and may in the future, enter into derivative arrangements for a portion of our crude 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 crude 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 over-the-counter 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 a new version of the rule, with respect to which the comment period has closed but a final rule has not been issued. 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 do not qualify for the commercial 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 Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, 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.

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 2018, we may be required to record further 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.

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

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.

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 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 June 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 will expand the previously issued NSPS Subpart OOOO requirements issued in 2012 by using certain equipment-specific emissions control practices. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards, but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect. Future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, and any other new methane emission standards imposed on the oil and gas sector could result in increased costs to our or our customers' operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. Moreover, in December 2015, the United States joined other countries of the United Nations in preparing an agreement requiring member countries to review and establish goals for limiting GHG emissions. This "Paris Agreement" was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions but, rather, includes pledges to voluntarily limit or reduce future emissions. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time. 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.

Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, 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. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

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 crude 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. Our failure to comply with these or other laws and regulations administered by these agencies could subject us to substantial penalties, 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 crude oil, natural gas and natural gas liquids transportation arrangements may hinder our access to crude oil, natural gas and natural gas liquids markets or delay our production. The availability of a ready market for our crude oil, natural gas and natural gas liquids production depends on a number of factors, including the demand for and supply of crude 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 crude 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.

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

Recently enacted legislation, commonly referred to as the Tax Cuts and Jobs Act, made significant changes to U.S. tax laws. While past legislative proposals have included changes to certain key U.S. federal income tax provisions currently available to oil and gas companies, including (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures, these specific changes were not included in the Tax Cuts and Jobs Act. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. However, the Tax Cuts and Jobs Act (i) eliminates the deduction for certain domestic production activities, (ii) imposes new limitations on the utilization of net operating losses, and (iii) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. Future changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to stringent laws and regulations, including environmental requirements 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 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.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental natural resource and property damages. We maintain insurance coverage for sudden and accidental environmental damages; however, it is possible that coverage might not be sufficient in a catastrophic event. Accordingly, we may be subject to liability, or we may be required to cease production from properties in the event of environmental damages. The trend in environmental laws and regulations is to place more stringent restrictions and limitations on activities that may affect the environment. For example, in October 2015, the EPA issued a final rule lowering the National Ambient Air Quality Standard for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either “attainment/unclassifiable” or “unclassifiable” but had not yet issued non-attainment designations for the remaining areas of the U.S. not addressed in the November 2017 final rule. States are also expected to implement requirements as a result of this NAAQs final rule, which could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Compliance with this final rule could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital or operating expenditures. In another example, in June 2015, the EPA and the Corps published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States including wetlands, but legal challenges to this rule followed. The 2015 rule was stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases in the matter and, in January 2017, the U.S. Supreme Court agreed to hear the case. The EPA and Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the Clean Water Act’s jurisdiction, and published a proposed rule in November 2017 specifying that the contested June 2015 rule would not take effect until two years after the November 2017 proposed rule was finalized and published in the Federal Register. Recently, on January 22, 2018, the U.S. Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; consequently, while implementation of the 2015 rule currently remains stayed, the previously-filed district court cases will be allowed to proceed. As a result of these recent developments, future implementation of the June 2015 rule is uncertain at this time but to the extent any rule expands the scope of the Clean Water Act’s jurisdiction, drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, we can provide no assurance that our future compliance with existing laws and regulations, these recently adopted rulemakings, or any new or amended legal requirements will not have a material adverse effect on our business, financial condition and results of operations.

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

We may incur significant environmental costs 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 crude 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 crude 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, in February 2014, the EPA 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. The EPA also published final rules under the CAA in 2012 and in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing. Additionally, in June 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 and, in May 2014, published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. The BLM published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands. However, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule, the BLM appealed the decision to the U.S. Circuit Court of Appeals for the Tenth Circuit in July 2016, the appellate court issued a ruling in September 2017 to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in response to the BLM's issuance of a proposed rulemaking to rescind the 2015 rule and, in December 2017, the BLM published a final rule rescinding the March 2015 rule. In January 2018, litigation challenging the BLM's rescission of the 2015 rule was brought in federal 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 of the State of New York in 2015. 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. 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 delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

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 BOEM, 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 lease 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 consider the adoption or enforcement of more stringent financial assurance regulatory initiatives that 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 an updated 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 liabilities. 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. During 2017, however, with the issuance of Order 3350, the BSEE and the BOEM have been directed 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. Consequently, during 2017, 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 sole 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 sole liabilities. 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 the current or future 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 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 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 much more 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. The agency is responsible for leading the most aggressive and comprehensive reforms to offshore oil and natural gas regulation and oversight in U.S. history. Their reforms have tightened requirements for everything from well and blowout preventer design and workplace safety to corporate accountability. However, as a result of the issuance of Order 3350 during 2017, the BSEE is reconsidering a number of regulatory initiatives governing offshore oil and gas safety and performance-related activities. For example, on December 29, 2017, the BSEE published proposed revisions to its regulations regarding offshore drilling safety equipment, which proposal includes the removal of the requirement 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. The December 2017 proposed rule has not been finalized and there remains substantial uncertainty as to the scope and extent of any revisions to existing oil and gas safety and performance-related regulations and other regulatory initiatives that ultimately will be adopted by the BSEE pursuant to the agency’s review process.

Additionally, the Outer Continental Shelf Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and a periodic unscheduled (unannounced) inspection 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 a violation, the inspector issues an Incident of Noncompliance ("INC") to the operator and uses one of two main enforcement actions (warning or shut-in), depending on the severity of the violation. If the violation is not severe or threatening, a warning INC is issued. The warning INC must be corrected within a reasonable amount of time specified on the INC. The shut-in INC may be for a single component (a portion of the facility) or the entire facility. The violation 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. 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 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.

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.

We may be unable to successfully integrate the properties and assets we acquire with our existing operations.

Integration of the properties and assets we acquire may be a complex, time consuming and costly process. 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. The difficulties of integrating these assets and properties present numerous risks, including:

- Acquisitions may prove unprofitable and fail to generate anticipated cash flows.
- 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.

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. As a result, the anticipated benefits of acquiring assets and properties may not be fully realized, if at all.

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 crude 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 crude oil, natural gas and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

In connection with the Acquisition, we entered into a new area 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 as a result of the Acquisition.

We have a limited operating history in West Texas. As a result of the Acquisition, 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 of the Acquisition may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

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 facility of $85.4 million, an increase of one percentage point in the interest rates would have resulted in an increase in interest expense during 2017 of $0.9 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, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks, ransomware and other security issues.

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, 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 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.

RISK FACTORS RELATED TO AN INVESTMENT IN OUR COMMON STOCK

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 crude oil, natural gas and natural gas liquids, domestically and globally;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- 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, terrorist attacks and acts of war.

Average natural gas and crude 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 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 senior secured revolving credit agreement and second lien 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 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, 2017, we had 94,833 stock options outstanding 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 organizational documents may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our certificate of incorporation and bylaws may make it more difficult for, or prevent a third party from, acquiring control of us without the approval of our board of directors. These provisions:

- permit us to issue, without any further vote or action by the stockholders, shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

- require special meetings of the stockholders to be called by the Chairman of the board of directors, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;

- require business at special meetings to be limited to the stated purpose or purposes of that meeting;

- require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;

- require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and

- permit directors to fill vacancies in our board of directors.

We are subject to the Delaware business combination law.

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a "business combination" with an "interested stockholder" for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a "business combination" as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an "interested stockholder" as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation's voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

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. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law.

Our business could be negatively affected by security threats, including cybersecurity threats and other disruptions.

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

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

None

Item 2. ***Properties***

As of December 31, 2017, we operated all of our offshore wells, with an average working interest of 54%, and operated 48% of our onshore wells with an average working interest of 69%. As of December 31, 2017, our properties were located in the following regions: Offshore Gulf of Mexico, Southeast Texas, South Texas, West Texas and Other.

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,		
	2017	2016	2015
Property acquisition costs:			
Unproved	$ 6,540	$ 29,767	$ 11,453
Proved	—	—	—
Exploration costs	8,158	9,126	29,477
Development costs	45,016	1,890	20,120
Total costs	$ 59,714	$ 40,783	$ 61,050

Included in unproved property acquisition costs for the year ended December 31, 2017, is $5.9 million related to our acquisition of unproved property in the Southern Delaware Basin.

Included in unproved property acquisition costs for the year ended December 31, 2016, is $27.0 million related to our acquisition of unproved property in the Southern Delaware Basin.

Included in unproved property acquisition costs for the year ended December 31, 2015, is $5.0 million related to Natrona and Weston counties, Wyoming.

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,		
	2017	2016	2015
Property acquisition costs	$ —	$ —	$ —
Exploration costs	—	—	—
Development costs	429	395	4,503
Total costs incurred	$ 429	$ 395	$ 4,503

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,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	1	0.5	1	0.8	5	2.9
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	1	0.4	—	—	1	0.8
Non-productive (offshore)	—	—	—	—	—	—
Total	2	0.9	1	0.8	6	3.7

	Year Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive (onshore)	4	1.9	—	—	9	5.3
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	4	1.9	—	—	9	5.3

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 crude 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, 2017.

	Developed Acreage (1)		Undeveloped Acreage (1)	
	Gross	Net (2)	Gross	Net (2)
Offshore GOM	9,618	6,828	—	—
Southeast Texas	22,044	13,143	7,262	3,994
South Texas	78,990	34,537	10,617	6,299
West Texas	6,139	2,883	10,316	3,929
Other [3]	9,956	5,735	62,517	41,733
Total	126,747	63,126	90,712	55,955

(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 includes acreage in Louisiana, Mississippi, Wyoming, North Texas and East Texas.

Some of our offshore and 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,					
	2018		2019		2020	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Offshore GOM	—	—	—	—	—	—
Southeast Texas	328	245	272	264	—	—
South Texas	3,618	1,809	100	50	—	—
West Texas	3,174	1,587	2,291	1,059	650	299
North Texas	4,195	—	—	—	—	—
Wyoming	8,267	10,256	7,880	6,039	5,521	4,417
Total	19,582	13,897	10,543	7,412	6,171	4,716

Production, Price and Cost History

See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

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, 2017:

	Natural Gas Wells		Oil Wells	
	Gross Wells (1)	Net Wells (2)	Gross Wells (1)	Net Wells (2)
Offshore GOM	11	6.0	—	—
Southeast Texas	34	19.7	47	25.3
South Texas	171	74.4	46	22.1
West Texas	—	—	6	2.9
Other	23	4.9	12	4.7
Total	239	105.0	111	55.0

(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.

Natural Gas and Oil Reserves

Estimates of proved reserves and future net revenue as of December 31, 2017, 2016 and 2015 were prepared by NSAI and Cobb, 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”). Approximately 69% and 31% of the proved reserves estimates shown herein at December 31, 2017 have been independently prepared by Cobb and NSAI, respectively. Cobb prepared the proved reserves estimates as of December 31, 2017, 2016 and 2015 for all of our offshore properties and our onshore Southern Delaware Basin reserves as of December 31, 2017, while NSAI prepared the proved reserves estimates as of December 31, 2017, 2016 and 2015 for our remaining onshore properties.

The technical individual at NSAI responsible for the preparation of our reserve estimates as of December 31, 2017, 2016, and 2015 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 technical individual at Cobb responsible for overseeing the preparation of our reserve estimates as of December 31, 2017, 2016, and 2015 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 estimates of proved reserves and future net revenue as of December 31, 2017, 2016 and 2015 were reviewed by our corporate reservoir engineering department that is independent of the operations department. The corporate reservoir engineering department interacts with geoscience, operating, accounting and marketing departments to review the integrity, accuracy and timeliness of the data, methods and assumptions used 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 Senior Vice President - Engineering 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 Senior Vice President - Engineering has a Bachelor of Science degree in Petroleum Engineering from the University of Texas and over 40 years of industry experience with positions of increasing responsibility. He 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 controls over the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is communicated to our reservoir engineers quarterly, is confirmed when our third-party reservoir engineers hold technical meetings with geologists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in Internal Controls - 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, 2017	2016	2015
Crude Oil and Condensate (MBbl) [(1)]			
Developed	3,364	2,158	2,869
Undeveloped	7,285	1,266	1,922
Total	10,649	3,424	4,791
Natural Gas (MMcf) [(1)]			
Developed	82,133	95,396	113,952
Undeveloped	9,586	9,657	12,176
Total	91,719	105,053	126,128
Natural Gas Liquids (MBbl) [(1)]			
Developed	3,596	3,509	4,354
Undeveloped	2,011	850	1,040
Total	5,607	4,359	5,394
Total MMcfe			
Developed	123,895	129,399	157,288
Undeveloped	65,359	22,351	29,950
Total [(2)]	189,254	151,750	187,238
Proved developed reserves percentage	65 %	85 %	84 %
Prices utilized in estimates [(3)]:			
Crude oil ($/Bbl)	$ 47.41	$ 38.67	$ 44.53
Natural gas ($/MMBtu)	$ 2.92	$ 2.43	$ 2.63
Natural gas liquids ($/Bbl)	$ 18.59	$ 13.62	$ 14.41

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

(2) During the year ended December 31, 2017, proved reserves increased by approximately 37.5 Bcfe primarily due to 63.1 Bcfe of new additions and extensions related to our drilling program and a 9.9 Bcfe positive revision of reserve estimates due to higher commodity prices, partially offset by 20.1 Bcfe in 2017 production and a 12.2 Bcfe decrease due to a reduction in proved undeveloped reserves required by SEC guidelines for those reserves that are not likely to be drilled within a five year period after those reserves are initially recorded.

(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). 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 were adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

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 crude 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 crude 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, 2017	December 31, 2016
Pre-tax net present value, discounted at 10%	$ 257,283	$ 166,228
Future income taxes, discounted at 10%	(1,376)	—
Standardized measure of discounted future net cash flows	$ 255,907	$ 166,228

The following table reflects our estimated proved reserves by category as of December 31, 2017 (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	3,157	73,694	3,066	111,037	59 %	$ 186,098
Proved developed non-producing	207	8,439	530	12,858	7 %	14,625
Proved undeveloped	7,285	9,586	2,011	65,359	34 %	56,560
Total	10,649	91,719	5,607	189,254	100 %	$ 257,283

Our estimated net proved reserves as of December 31, 2017 were approximately 34% crude oil and condensate, 48% natural gas and 18% natural gas liquids.

Proved Developed Reserves

Total proved developed reserves declined slightly from 129.4 Bcfe at December 31, 2016 to 123.9 Bcfe at December 31, 2017. This decline is primarily due to a 20.1 Bcfe decrease attributable to production during the year and a 1.7 Bcfe negative performance revision, partially offset by 10.7 Bcfe of extensions and additions related to our drilling program and a 7.0 Bcfe positive revision of reserve estimates due to higher commodity prices.

The following table presents the changes in our total proved developed reserves for the year ended December 31, 2017:

	Proved Developed Reserves (Mmcfe)
Proved developed reserves at December 31, 2016	129,399
Revisions of previous estimates [(1)]	7,008
Extensions, discoveries and other additions [(2)]	10,743
Purchase of minerals in place	—
Disposition of reserves in place [(3)]	(1,459)
Production	(20,123)
Negative revisions related to performance	(1,673)
Proved developed reserves at December 31, 2017	123,895

(1) Positive revisions due to higher commodity prices.

(2) Extensions, discoveries and additions are primarily related to our assets in the Southern Delaware Basin in West Texas.

(3) Related to the sale of our assets in the North Bob West area and our operated assets in the Escobas area, both located in Southeast Texas.

Proved Undeveloped Reserves

Total proved undeveloped reserves (“PUDs”) increased from 22.4 Bcfe at December 31, 2016 to 65.4 Bcfe at December 31, 2017. As noted in the table below, this increase was primarily attributable to extensions and additions primarily related to the successful development of assets in West Texas, partially offset by the PUDs removed due to the SEC’s five year rule.

Future drilling plans and timelines are re-evaluated at the end of each calendar year based on updated reserve reports, current drilling cost estimates and product price forecast. Our development plan prioritizes reserves based on the capital requirements and net present value of potential wells. 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 2017 and 2016 was 0% and 0%, 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 date of originally adding the reserves. The Company's financial resources are expected to be sufficient to drill all of the remaining 65.4 Bcfe of proved undeveloped reserves within the five year period. Development costs relating to the 65.4 Bcfe at December 31, 2017 are projected to be approximately $124.6 million over the next five years.

The following table presents the changes in our total proved undeveloped reserves for the year ended December 31, 2017:

	Proved Undeveloped Reserves (Mmcfe)
Proved undeveloped reserves at December 31, 2016	22,351
Revisions of previous estimates [1]	2,889
Extensions, discoveries and other additions [2]	52,333
Purchase of minerals in place	—
Expired undeveloped reserves	(12,214)
Disposition of reserves in place	—
Conversion to proved developed	—
Proved undeveloped reserves at December 31, 2017	65,359

(1) Positive revisions due to higher commodity prices.

(2) Extensions, discoveries and additions are primarily related to our assets in the Southern Delaware Basin in West Texas.

Significant Properties

Summary proved reserve information for our properties as of December 31, 2017, by region, is provided below (excluding reserves attributable to our 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	432	61,430	1,889	75,359	$ 124,316
Southeast Texas	2,092	11,448	1,146	30,874	37,005
South Texas	1,984	10,196	598	25,687	37,060
West Texas	5,944	8,064	1,965	55,516	55,879
Other	197	581	9	1,818	3,023
Total	10,649	91,719	5,607	189,254	$ 257,283

(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 Investment in Exaro

Estimates of proved reserves and future net revenue as of December 31, 2017 and 2016 associated with our investment in 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.

Reserves as of December 31, 2017 and 2016 were reviewed by our corporate reservoir engineering department as described above. The technical individual at Von Gonten responsible for overseeing the preparation of our reserve estimates as of December 31, 2017 and December 31, 2016 has over 17 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 Investment in Exaro:

	December 31, 2017	December 31, 2016	December 31, 2015
Crude Oil (MBbl)			
Developed	325	360	442
Undeveloped	4	—	—
Total	329	360	442
Natural Gas (MMcf)			
Developed	28,443	30,441	36,074
Undeveloped	303	—	—
Total	28,746	30,441	36,074
Total MMcfe			
Developed	30,390	32,600	38,724
Undeveloped	329	—	—
Total [3]	30,719	32,600	38,724
Proved developed reserves percentage	99 %	100 %	100 %
Standardized measure [1]	$ 24,366	$ 19,778	$ 31,298
Prices utilized in estimates [2]			
Crude oil ($/Bbl)	$ 48.91	$ 39.60	$ 44.28
Natural gas ($/MMBtu)	$ 3.02	$ 2.44	$ 2.71

(1) The Company's share of the standardized measure of discounted future net cash flows attributable to our investment in Exaro does not include the effect of income taxes because Exaro is treated 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, 2017, the decrease in Exaro's proved reserves attributable to our Investment in Exaro was approximately 1.9 Bcfe.

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of December 31, 2016, 2015 and 2014 are disclosed in "Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Disclosures (Unaudited)". Reserves as of December 31, 2016, 2015 and 2014 were based on reserve reports generated by NSAI and Cobb, while the reserves associated with our 37% 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.

In July 2010, several parties associated with a limited partnership, formed to invest in oil and gas properties, and that was dissolved in 1995, filed suit against a subsidiary of the Company and several co-defendants in the district court for Madison County in Texas. The plaintiffs claim to own or have rights in certain oil and gas properties situated in Madison County, Texas by virtue of the partnership having interests in addition to those it held of record at the time of its dissolution, which were distributed to the partners in connection with such dissolution. A predecessor of the subsidiary of the Company involved in this case acquired a portion of the interests now claimed by the plaintiffs from a successor to the general partner of the aforementioned partnership in 2000. The case went to trial in December 2017. As the Court did not allow virtually all of the plaintiff's claims, a nominal settlement agreement was executed to settle all claims.

In November 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 decade-old poorly documented transactions. Based on prior summary judgments, the trial court has 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. In the fourth quarter of 2017 the Court of Appeals issued its opinion and affirmed the trial court's summary decision. The Company continues to vigorously defend this lawsuit and has filed a motion for rehearing with the Court of Appeals, and if denied, will petition the Texas Supreme Court.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the district court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The trial court has entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds. The plaintiff appealed the trial court's decision to the applicable state Court of Appeals. On December 14, 2017, the Court of Appeals affirmed the judgement in the Company's favor. The plaintiff has filed a motion for rehearing. The Company continues to vigorously defend this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

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". The table below shows the high and low sales prices per share of our common stock for the periods indicated.

	High	Low
Year Ended December 31, 2017		
Quarter Ended March 31, 2017	$ 10.15	$ 5.62
Quarter Ended June 30, 2017	$ 8.19	$ 5.83
Quarter Ended September 30, 2017	$ 6.89	$ 3.97
Quarter Ended December 31, 2017	$ 5.43	$ 2.22
Year Ended December 31, 2016		
Quarter Ended March 31, 2016	$ 12.84	$ 3.68
Quarter Ended June 30, 2016	$ 14.14	$ 10.52
Quarter Ended September 30, 2016	$ 12.85	$ 8.25
Quarter Ended December 31, 2016	$ 11.98	$ 7.43

From the period from January 1, 2018 to March 5, 2018, our common stock traded at prices between $2.80 and $5.97 per share. During the quarter ended September 30, 2016, we completed an underwritten public offering of 5,360,000 shares for net proceeds of approximately $50.5 million.

General

The following descriptions are summaries of material terms of our common stock, preferred stock, certificate of incorporation and bylaws. This summary is qualified by reference to our certificate of incorporation, bylaws and the designations of our preferred stock, which are filed as exhibits to this report on Form 10-K, and by the provisions of applicable law.

Common Stock

We are authorized to issue up to 50 million shares of common stock. As of March 5, 2018, there were approximately 30.9 million shares of common stock issued and 25.5 million shares of common stock outstanding held by approximately 228 registered shareholders.

Holders of common stock are entitled to one vote for each share held of record on each matter submitted to a vote of stockholders and, in the event of liquidation, to share ratably in the distribution of assets remaining after payment of liabilities (including preferential distribution and dividend rights of holders of preferred stock). Holders of common stock have no cumulative rights. The holders of a plurality of the outstanding shares of the common stock have the ability to elect all of the directors.

Holders of common stock have no preemptive or other rights to subscribe for shares. 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 facility with Royal Bank of Canada 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.

Preferred 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. No preferred stock was outstanding at December 31, 2017.

Share-Based Compensation

The following table sets forth information about our equity compensation plans at December 31, 2017:

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans
Amended and Restated 2009 Incentive Compensation Plan - approved by security holders	—	$ —	2,002,492 *
2005 Stock Incentive Plan ("Crimson Plan")	94,833	$ 57.69	—

* Excludes 382,744 Performance Stock Units granted in 2016 and 2017.

Amended and Restated 2009 Incentive Compensation Plan

On September 15, 2009, the Company's board of directors (the "Board") adopted the Contango Oil & Gas Company Equity Compensation Plan (the "Original 2009 Plan"), which was approved by shareholders on November 19, 2009. On April 10, 2014, the Board amended and restated the Original 2009 Plan through the adoption of the Contango Oil & Gas Company Amended and Restated 2009 Incentive Compensation Plan (the "2009 Plan"), which was approved by shareholders on May 20, 2014. The 2009 Plan provides for both cash awards and equity awards (such as restricted stock, performance stock units and options) to officers, directors, employees and consultants of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board.

Stock options issued under the 2009 Plan must have an exercise price 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.

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 performance metrics and targeted performance goals under the CIBP are approved annually, in advance, by the Compensation Committee and/or the Board. Upon achieving the performance levels established each year, bonus awards under the CIBP will be calculated as a percentage of base salary of each employee for the plan year. The CIBP 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. Prior to the 2017 performance year, the LTIP metrics and performance measures were also determined, in advance, by the Board, with ultimate grants for a performance year determined at the end of the performance year based on performance compared to the previously established goals. The ultimate LTIP awards for each year were also distributed during the first quarter of the following year with a three year vesting period. Beginning with the 2017 performance year, the Company discontinued the practice of awarding LTIP grants on a look-back basis based on performance compared to operational goals, and implemented the policy of determining an appropriate number of performance stock units ("PSUs") to be granted to all employees at the beginning of the year, with a specified number of those granted shares vesting ratably, typically over a three period. The other portion of those grants will vest at the end of a three year performance period, with the ultimate number of shares to be issued based on the Company's stock performance vs. that of the Company's peer group during that three year period.

The CIBP awards will be paid in cash while the LTIP awards will consist of restricted common stock, PSUs and/or stock options that vest over three or four years. The number of shares of restricted common stock, the PSUs 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.

Restricted Stock Awards

During the year ended December 31, 2017, the Company granted 457,701 restricted stock awards under the 2009 Plan to officers, employees and directors of the Company, while 137,021 restricted shares issued under the 2009 Plan were forfeited by former employees and are available to be reissued. During the year ended December 31, 2016, 580,141 restricted stock awards were granted under the 2009 Plan to officers, employees and directors of the Company, while 17,864 restricted shares were forfeited by former employees and are available to be reissued. During the year ended December 31, 2015, 270,091 restricted stock awards were granted under the 2009 Plan to officers, employees and directors of the Company pursuant to the LTIP, while 12,534 restricted shares were forfeited by former employees and are available to be reissued. As of December 31, 2017, there were 731,073 shares of unvested restricted stock outstanding.

Performance Stock Units

During the year ended December 31, 2017, the Company granted 30,000 PSUs to a new employee, at a weighted average fair value of $8.32 per unit and 160,908 PSUs to executive officers, as part of their overall compensation package, at a value of $13.91 per unit. All prices were determined using the Monte Carlo simulation model. Also during the year, 99,363 PSUs were forfeited by former employees.

During the year ended December 31, 2016, the Company issued 285,800 PSUs to all employees as part of its LTIP, at a fair value of $16.32 per unit, as determined using the Monte Carlo simulation method. Additionally, the Company issued 6,699 PSUs to new employees, at a fair value of $13.06 per unit, also determined using the Monte Carlo simulation method. Former employees forfeited 1,300 PSUs during the year ended December 31, 2016. 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.

2005 Stock Incentive Plan

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

During the year ended December 31, 2017, 5,197 restricted stock awards previously issued under the 2005 Plan were forfeited by former employees, while 17,072 stock options previously issued were forfeited. During the year ended December 31, 2016, 1,226 restricted stock awards issued under the 2005 Plan were forfeited by former employees, while 4,556 stock options previously issued were forfeited. During the year ended December 31, 2015, the Company granted 7,030 restricted stock awards under the 2005 Plan to a new employee, while 189 restricted stock awards were forfeited by former employees. Additionally, during the year ended December 31, 2015, 13,473 stock options previously issued were forfeited. As of December 31, 2017, there were no shares of restricted stock outstanding and 94,833 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 three years.

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. No shares were purchased for the years ended December 31, 2017, 2016 and 2015. As of December 31, 2017, the Company has $31.8 million available under its share repurchase program.

In addition, the Company repurchased the following shares, outside of the repurchase program, from employees for the payment of withholding taxes due on vesting shares of restricted stock previously issued under our stock-based compensation plans:

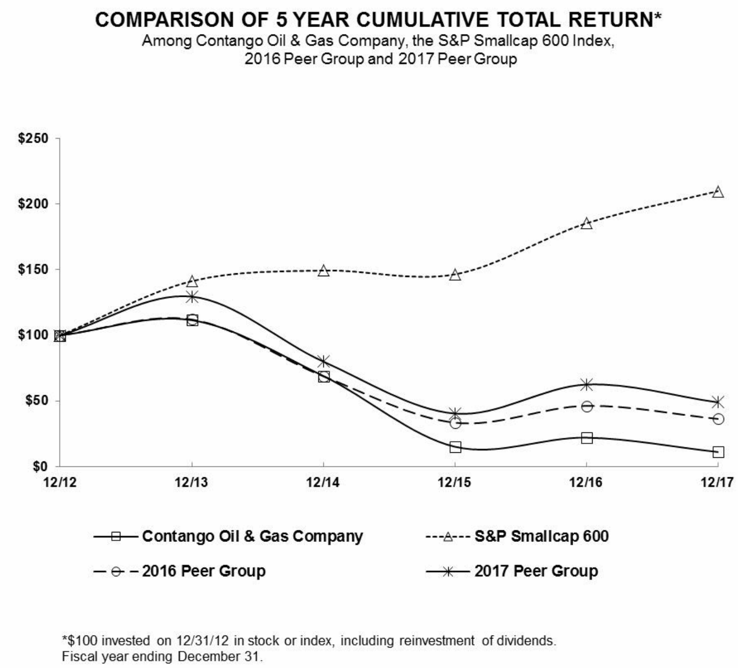
Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
February 2017	174	$ 8.08	n/a	n/a
March 2017	11,693	$ 6.18	n/a	n/a
April 2017	10,998	$ 7.88	n/a	n/a
June 2017	116	$ 6.65	n/a	n/a
October 2017	22,421	$ 4.11	n/a	n/a
November 2017	276	$ 3.09	n/a	n/a
December 2017	2,690	$ 2.96	n/a	n/a

Stock Performance Graph

The following graph compares the yearly percentage change from December 31, 2012 until December 31, 2017 in the cumulative total stockholder return on our common stock to the cumulative total return on the S&P Smallcap 600 Index and a peer group of independent oil & gas exploration companies selected by us.

As of December 31, 2016, the companies in our selected peer group included Carrizo Oil & Gas, Matador Resources, Bill Barrett, Denbury Resources, SRC Energy, Abraxas Petroleum, Sanchez Energy, EP Energy, Halcon Resources, W&T Offshore and Approach Energy (collectively, the "2016 Peer Group"). For the year ended December 31, 2017, we elected to use the same PSU peer group used under the Company's LTIP to determine the number of shares of common stock to be issued to employees at the end of the three year performance period. That peer group consisted of: Abraxas Petroleum Corp, Approach Resources Inc, Bill Barrett Corp, Callon Petroleum Co, Carrizo Oil & Gas Inc, Denbury Resources Inc, Energen Corp, EP Energy Corp, Extraction Oil & Gas Inc, Halcon Resources Corp, Laredo Petroleum Inc, Matador Resources Co, Murphy Oil Corp, Oasis Petroleum Inc, QEP Resources Inc, Sanchez Energy Corp, SM Energy Co, SRC Energy Inc, W&T Offshore Inc, Whiting Petroleum Corp and WPX Energy Inc, (collectively, the "2017 Peer Group").

Our common stock began trading on the NYSE American (previously NYSE MKT) on January 19, 2001 and before that had traded on the Nasdaq over-the-counter Bulletin Board. The graph assumes that a $100 investment was made in our common stock and each index on December 31, 2012, adjusted for stock splits and dividends. The stock performance for our common stock is not necessarily indicative of future performance.



	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017
Contango Oil & Gas Company	100.00	111.57	69.03	15.13	22.05	11.12
S&P Smallcap 600	100.00	141.31	149.45	146.50	185.40	209.94
2016 Peer Group	100.00	112.08	68.87	33.47	46.28	36.35
2017 Peer Group	100.00	129.55	80.05	40.40	62.52	48.93

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

On October 1, 2013, the Company's board of directors approved a change in fiscal year end from June 30 to December 31. Unless otherwise noted, all references to "years" in this report refer to the twelve-month period which ends on December 31 of each year. The following selected financial data for the years ended December 31, 2017, 2016 and 2015 have been derived from the audited consolidated financial statements of Contango contained in this Form 10-K. The following selected financial data for the years ended December 31, 2014 and 2013 have been derived from the audited consolidated financial statements of Contango contained in our Form 10-K for the applicable fiscal year. The selected consolidated financial data (not including proved reserve information) set forth below is for continuing operations and should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the consolidated financial statements and notes to those consolidated financial statements included elsewhere in this Form 10-K.

Selected financial data for the years ended December 31, 2017, 2016, 2015, 2014 and 2013 include results of operations and cash flows of Crimson starting from October 1, 2013, the date of the Merger. Consolidated balance sheet and reserves information as of December 31, 2017, 2016, 2015, 2014 and 2013 include the balance sheet and reserves information of Crimson and its subsidiaries adjusted in accordance with the acquisition method of accounting, which requires that assets acquired and liabilities assumed in the Merger be recorded at their fair value at the date of acquisition with the difference between the purchase price and value of assets and liabilities be recorded as goodwill. No goodwill was recognized as a result of the Merger between Contango and Crimson.

Selected financial information for the five years ended December 31, 2017 is as follows (dollars in thousands, except per share amounts):

	Year Ended December 31				
	2017	2016	2015	2014	2013
Natural gas and oil sales [1]	$ 78,545	$ 78,183	$ 116,505	$276,458	$164,121
Income (loss) [2]	$(17,643)	$(58,029)	$(335,048)	$ (21,874)	$ 41,362
Net income (loss) attributable to common stock	$(17,643)	$(58,029)	$(335,048)	$ (21,874)	$ 41,362
Net income (loss) per share:					
Basic	$ (0.71)	$ (2.71)	$ (17.67)	$ (1.15)	$ 2.56
Diluted	$ (0.71)	$ (2.71)	$ (17.67)	$ (1.15)	$ 2.56
Weighted average shares outstanding:					
Basic	24,686	21,424	18,965	19,059	16,156
Diluted	24,686	21,424	18,965	19,059	16,158

	Year Ended December 31				
	2017	2016	2015	2014	2013
Working capital (deficit) [3]	$ (34,764)	$ (43,835)	$ (18,689)	$ (65,975)	$ (33,162)
Capital expenditures	$ 58,376	$ 38,966	$ 55,565	$188,529	$ 62,552
Long term debt	$ 85,380	$ 54,354	$115,446	$ 63,359	$ 90,000
Shareholders' equity	$224,600	$236,405	$237,843	$567,466	$593,050
Total assets	$381,453	$376,514	$416,756	$843,415	$910,304
Proved Reserve Data:					
Total proved reserves (Mmcfe) [4]	189,254	151,750	187,238	275,193	313,866
Pre-tax net present value (discounted 10%)	$257,283	$166,228	$249,406	$796,871	987,213
Standardized measure [4]	$255,907	$166,228	$249,406	$648,016	771,443

(1) The increase in natural gas and oil sales for the year ended December 31, 2017 is primarily attributable to higher commodity prices during the year. The decrease in natural gas and oil sales for the year ended December 31, 2016 is attributable to lower commodity prices during the year and lower production resulting from the significant reduction in our capital program. The decrease in natural gas and oil sales for the year ended December 31, 2015 is attributable to the decline in commodity prices during the fourth quarter of 2014 and during 2015, combined with lower production as a result of a reduction in our 2015 drilling program. The increase in natural gas and oil sales for the year ended December 31, 2014 is attributable to the Merger with Crimson and new production from our 2013 and 2014 drilling program.

(2) During the year ended December 31, 2017, we recognized approximately $0.3 million for impairment of proved properties, related to revised estimated reserves for our TMS properties. Additionally, we recognized $1.5 million related the partial impairment of two unused offshore platforms in onshore storage.

During the year ended December 31, 2016, we recognized approximately $0.7 million for impairment of proved properties, substantially all of which was directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from the associated reserves. Additionally, we recognized $6.8 million related to our unproved properties in Fayette and Gonzales counties Texas and $2.9 million related to our unproved acreage in Natrona County, Wyoming.

During the year ended December 31, 2015, we recognized approximately $269.6 million for impairment of proved properties, substantially all of which was directly related to the decline in commodity prices and the resulting impact on estimated future net cash flows from the associated reserves. Additionally, we recognized approximately $16.3 million for impairment and partial impairment of certain unproved properties and onshore prospects primarily due to the sustained low commodity price environment and expiring leases.

During the year ended December 31, 2014, we reached a total depth on our Ship Shoal 255 well, and no hydrocarbons were found. As a result, we recognized $31.5 million in exploration expense for the cost of drilling the well and $15.6 million in impairment expense, including $3.5 million related to leasehold costs and $12.1 million related to the platform located in Ship Shoal 263 block which was expected to be used by the Ship Shoal 255 had it been successful. Additionally, during the year ended December 31, 2014, we revised estimated proved reserves for South Timbalier 17 and our TMS properties, resulting in non-cash impairment expenses of approximately $11.4 million. During the year ended December 31, 2014, we also recognized impairment expense of approximately $20.1 million related to full or partial impairment of certain unproved properties due to expiring leases and leases not likely to be drilled.

(3) The increase in the deficit in working capital for the years ended December 31, 2017 and 2016 was primarily related to our activity in West Texas, beginning in the fourth quarter of 2016. The decrease in the deficit in working capital during 2015 was a result of the decrease in drilling activity and the satisfaction of trade obligations existing at the beginning of the year, which were attributable to a more active 2014 drilling program. The increase in the working capital deficit for the year ended December 31, 2014 was primarily attributable to the higher trade obligations associated with the drilling program in late 2014 and a decrease in trade receivables associated with the decline in commodity prices during the fourth quarter of 2014. On October 1, 2013, in connection with the Merger, we entered into a revolving credit facility with Royal Bank of Canada and other lenders.

(4) During the year ended December 31, 2017, our proved reserves increased by approximately 37.5 Bcfe and our standardized measure increased by approximately $89.7 million. This increase is primarily due to 63.1 Bcfe of additions and extensions related to our assets in West Texas and a 9.9 Bcfe positive revision of reserve estimates due to higher commodity prices, partially offset by 20.1 Bcfe in 2017 production and a 12.2 Bcfe decrease due a reduction in proved undeveloped reserves required by SEC guidelines for those reserves that are not likely to be drilled within a five year period after those reserves are initially recorded.

During the year ended December 31, 2016, our proved reserves decreased by approximately 35.5 Bcfe and our standardized measure decreased by approximately $83.2 million. This decrease is primarily due to 26.0 Bcfe of production, an 8.3 Bcfe negative revision of reserve estimates due to low commodity prices and 4.2 Bcfe due to the sale of our Colorado properties, partially offset by 2.5 Bcfe related to positive performance revisions.

During the year ended December 31, 2015, our proved reserves decreased by approximately 88.0 Bcfe and our standardized measure decreased by approximately $398.6 million. This decrease is primarily attributable to 2015 production and to the impact of the dramatic decline in commodity prices on the value and volume of our proved reserves and in part to the impact of the significant reduction in our capital spending in response to the low and uncertain commodity price environment.

During the year ended December 31, 2014, our proved reserves decreased by approximately 38.7 Bcfe and our standardized measure decreased by approximately $123.4 million. This decrease is primarily attributable to 40.3 Bcfe of production and a 22.4 Bcfe negative revision of proved developed producing reserves at our Eugene Island 11 field due to a change in forecasted condensate yield and ultimate field abandonment pressure; these decreases were partially offset by 36.1 Bcfe for extensions and discoveries.

During the year ended December 31, 2013, our proved reserves increased by approximately 92.8 Bcfe and our standardized measure increased by approximately $383.4 million, primarily as a result of our Merger with Crimson. Also contributing to the increase was the exercise of our preferential right to purchase approximately 17.0 Bcfe related to our five Contango-operated Dutch wells, slightly offset by 28.2 Bcfe of production, a 19.2 Bcfe decrease in our Dutch and Mary Rose reserve estimates based upon additional pressure data, and a 2.5 Bcfe decrease in our Vermilion 170 reserve estimates, as determined by our reservoir engineer.

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. 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 and Wyoming properties and to use that cash flow to explore, develop, exploit, produce and acquire crude oil and natural gas properties in the onshore Texas and Rocky Mountain regions of the United States.

On October 1, 2013, we completed a merger with Crimson Exploration Inc. ("Crimson") (the "Merger"). We have historically focused our operations in the GOM, but the Merger gave us access to high rate of return onshore prospects in known, prolific producing areas as well as long-life resource plays. In 2015, prior to the decline in crude oil and natural gas prices, our drilling activity focused primarily on the Woodbine oil and liquids-rich play in Madison and Grimes counties, Texas (our Southeast Texas Region), in the Cretaceous Sands in Fayette and Gonzales counties, Texas (our South Texas Region) and Wyoming where we were targeting the Mowry Shale and the Muddy Sandstone formations. Beginning in the second half of 2015, we reduced our drilling program in response to the challenging commodity price environment. As a result, until the latter half of 2016, our only drilling activity was in Weston County, Wyoming, where we completed our third well targeting the Muddy Sandstone formation. During the third quarter of 2016, we acquired a 12,100 operated gross acre position (5,000 net) in the Southern Delaware Basin in Pecos County, Texas, (the "Acquisition") and as of December 31, 2017, had increased our acreage in the Southern Delaware Basin to 16,500 gross acres (6,800 net). Since the Acquisition, we have begun production from seven wells in the Southern Delaware Basin and are waiting on completion of an eighth well. We currently expect that the Southern Delaware Basin position will continue to be the primary focus of our drilling program for 2018.

Additionally, we have (i) a 37% equity investment in Exaro Energy III LLC ("Exaro"), which 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. Until their sale in December 2016, we also had operated producing properties in the Denver Julesburg Basin ("DJ Basin") in Weld and Adams counties in Colorado.

Our production for the year ended December 31, 2017 was approximately 20.1 Bcfe (or 55.1 Mmcfe/d) and was 68% offshore and 32% onshore. Our production for the three months ended December 31, 2017 was approximately 4.8 Bcfe (or 51.8 Mmcfe/d) and was 66% offshore and 34% onshore. As of December 31, 2017, our proved reserves were approximately 40% offshore and 60% onshore and were 65% proved developed, which were approximately 61% offshore and 39% onshore.

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. The Merger with Crimson allowed the Company to add significant proved developed and undeveloped reserves and provided the Company with access to several onshore resource plays which have substantial reserve growth potential, including in oil and liquids rich plays that position us to move to a more balanced oil/gas profile.

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, 2016	**June 30, 2016**	**September 30, 2016**	**December 31, 2016**	**March 31, 2017**	**June 30, 2017**	**September 30, 2017**	**December 31, 2017**
Offshore GOM								
Dutch and Mary Rose (1)	45.9	43.3	39.3	39.5	35.4	36.3	32.2	30.8
Vermilion 170 (2)	6.5	6.2	4.0	4.9	4.6	3.1	4.2	3.5
South Timbalier 17 (3)	0.6	0.6	0.6	0.6	0.5	0.2	0.1	—
Southeast Texas (4)	16.4	13.9	12.1	10.1	8.6	8.2	7.8	7.5
South Texas (5)	7.4	7.4	7.5	7.5	6.4	5.6	4.6	5.8
West Texas	—	—	—	—	0.6	3.3	3.2	3.2
Other (6)	2.6	3.2	2.2	1.7	1.5	1.3	1.1	1.0
	79.4	74.6	65.7	64.3	57.6	58.0	53.2	51.8

(1) Includes a 26 day shut in for compressor repair during the three months ended March 31, 2017

(2) Includes a decreased production rate of 0.8 Mmcfe/d due to temporary pipeline limitations during the three months ended June 30, 2017.

(3) South Timbalier 17 ceased production in August 2017.

(4) Includes Woodbine production from Madison and Grimes counties and conventional production in others.

(5) Includes Eagle Ford and Buda production from Karnes, Zavala and Dimmit counties, and conventional production in others.

(6) Includes onshore wells primarily in Colorado, East Texas, and Wyoming during 2016 and onshore wells primarily in East Texas and Wyoming during 2017.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016; and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

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, 2017, 2016 and 2015. 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,			Year Ended December 31,		
	2017	2016	%	2016	2015	%
Revenues (thousands):						
Oil and condensate sales	$ 25,347	$ 23,006	10 %	$ 23,006	$ 43,230	(47)%
Natural gas sales	41,317	43,847	(6)%	43,847	59,058	(26)%
NGL sales	11,881	11,330	5 %	11,330	14,217	(20)%
Total revenues	$ 78,545	$ 78,183	— %	$ 78,183	$116,505	(33)%
Production:						
Oil and condensate (thousand barrels)						
Dutch and Mary Rose	89	120	(26)%	120	164	(27)%
Vermilion 170	10	16	(38)%	16	22	(27)%
Southeast Texas	151	239	(37)%	239	493	(52)%
South Texas	95	128	(26)%	128	178	(28)%
West Texas	133	—	100 %	—	—	— %
Other	40	94	(57)%	94	67	40 %
Total oil and condensate	518	597	(13)%	597	924	(35)%
Natural gas (million cubic feet)						
Dutch and Mary Rose	9,891	12,375	(20)%	12,375	14,736	(16)%
Vermilion 170	1,222	1,616	(24)%	1,616	2,050	(21)%
Southeast Texas	1,328	2,059	(36)%	2,059	3,136	(34)%
South Texas	1,112	1,528	(27)%	1,528	1,788	(15)%
West Texas	82	—	100 %	—	—	— %
Other	275	525	(48)%	525	904	(42)%
Total natural gas	13,910	18,103	(23)%	18,103	22,614	(20)%
Natural gas liquids (thousand barrels)						
Dutch and Mary Rose	310	378	(18)%	378	454	(17)%
Vermilion 170	20	42	(52)%	42	60	(30)%
Southeast Texas	115	217	(47)%	217	359	(40)%
South Texas	60	72	(17)%	72	87	(17)%
West Texas	12	—	100 %	—	—	— %
Other	—	7	(100)%	7	8	(13)%
Total natural gas liquids	517	716	(28)%	716	968	(26)%
Total (million cubic feet equivalent)						
Dutch and Mary Rose	12,283	15,364	(20)%	15,364	18,443	(17)%
Vermilion 170	1,402	1,965	(29)%	1,965	2,545	(23)%
Southeast Texas	2,924	4,792	(39)%	4,792	8,249	(42)%
South Texas	2,038	2,729	(25)%	2,729	3,379	(19)%
West Texas	947	—	100 %	—	—	— %
Other	529	1,132	(53)%	1,132	1,345	(16)%
Total production	20,123	25,982	(23)%	25,982	33,961	(23)%

	Year Ended December 31, 2017	2016	%	Year Ended December 31, 2016	2015	%
Daily Production:						
Oil and condensate (thousand barrels per day)						
Dutch and Mary Rose	0.2	0.3	(26)%	0.3	0.4	(27)%
Vermilion 170	—	—	(38)%	—	0.1	(27)%
Southeast Texas	0.4	0.7	(37)%	0.7	1.4	(52)%
South Texas	0.3	0.4	(26)%	0.4	0.5	(28)%
West Texas	0.4	—	100 %	—	—	— %
Other	0.1	0.2	(57)%	0.2	0.1	40 %
Total oil and condensate	1.4	1.6	(13)%	1.6	2.5	(35)%
Natural gas (million cubic feet per day)						
Dutch and Mary Rose	27.1	33.8	(20)%	33.8	40.4	(16)%
Vermilion 170	3.3	4.4	(24)%	4.4	5.6	(21)%
Southeast Texas	3.6	5.6	(36)%	5.6	8.6	(34)%
South Texas	3.0	4.2	(27)%	4.2	4.9	(15)%
West Texas	0.2	—	100 %	—	—	— %
Other	0.9	1.5	(48)%	1.5	2.4	(42)%
Total natural gas	38.1	49.5	(23)%	49.5	61.9	(20)%
Natural gas liquids (thousand barrels per day)						
Dutch and Mary Rose	0.9	1.0	(18)%	1.0	1.2	(17)%
Vermilion 170	—	0.1	(52)%	0.1	0.2	(30)%
Southeast Texas	0.3	0.6	(47)%	0.6	1.0	(40)%
South Texas	0.2	0.2	(17)%	0.2	0.2	(17)%
West Texas	—	—	100 %	—	—	— %
Other	—	0.1	(100)%	0.1	—	(13)%
Total natural gas liquids	1.4	2.0	(28)%	2.0	2.6	(26)%
Total (million cubic feet equivalent per day)						
Dutch and Mary Rose	33.7	42.0	(20)%	42.0	50.5	(17)%
Vermilion 170	3.8	5.4	(29)%	5.4	7.0	(23)%
Southeast Texas	8.0	13.1	(39)%	13.1	22.6	(42)%
South Texas	5.6	7.5	(25)%	7.5	9.3	(19)%
West Texas	2.6	—	100 %	—	—	— %
Other	1.4	3.0	(53)%	3.0	3.6	(16)%
Total production	55.1	71.0	(23)%	71.0	93.0	(23)%
Average Sales Price:						
Oil and condensate (per barrel)	$ 48.90	$ 38.52	27 %	$ 38.52	$ 46.80	(18)%
Natural gas (per thousand cubic feet)	$ 2.97	$ 2.42	23 %	$ 2.42	$ 2.61	(7)%
Natural gas liquids (per barrel)	$ 22.97	$ 15.79	45 %	$ 15.79	$ 14.68	8 %
Total (per thousand cubic feet equivalent)	$ 3.90	$ 3.01	30 %	$ 3.01	$ 3.43	(12)%
Expenses (thousands):						
Operating expenses	$ 27,183	$ 29,111	(7)%	$ 29,111	$ 37,840	(23)%
Exploration expenses	$ 1,106	$ 1,816	(39)%	$ 1,816	$ 11,979	(85)%
Depreciation, depletion and amortization	$ 47,215	$ 63,323	(25)%	$ 63,323	$133,380	(53)%
Impairment and abandonment of oil and gas properties	$ 2,395	$ 10,572	(77)%	$ 10,572	$285,877	(96)%
General and administrative expenses	$ 24,161	$ 26,802	(10)%	$ 26,802	$ 26,402	2 %
Gain (Loss) from investment in affiliates (net of taxes)	$ 2,697	$ 1,545	75 %	$ 1,545	$ (30,582)	(105)%
Other (Income) Expense	$ 2,780	$ (5,791)	(148)%	$ (5,791)	$ (719)	705 %
Selected data per Mcfe:						
Operating expenses	$ 1.35	$ 1.12	21 %	$ 1.12	$ 1.11	1 %
General and administrative expenses	$ 1.20	$ 1.03	17 %	$ 1.03	$ 0.78	32 %
Depreciation, depletion and amortization	$ 2.35	$ 2.44	(4)%	$ 2.44	$ 3.93	(37)%

Natural Gas, Oil and NGL Sales and Production

All of our revenues are from the sale of our natural gas, crude oil and natural gas liquids production. Our revenues may vary significantly from year to year depending on changes in commodity prices, which fluctuate widely, and production volumes. Our production volumes are subject to wide swings as a result of new discoveries, weather and mechanical related problems. In addition, the production rate associated with our oil and gas properties declines over time as we produce our reserves.

We reported revenues of approximately $78.5 million for the year ended December 31, 2017, compared to revenues of approximately $78.2 million for the year ended December 31, 2016. This slight increase in revenues was primarily attributable to higher oil and natural gas prices in 2017, which offset the decline in production caused by only adding five new producing wells in the Southern Delaware Basin since late 2016 and minor non-core property sales.

Total production for the year ended December 31, 2017 was approximately 20.1 Bcfe, or 55.1 Mmcfe/d, compared to approximately 26.0 Bcfe, or 71.0 Mmcfe/d, in the prior year. The decrease was attributable to a 6.7 Mmcfe/d decline in production resulting from normal field decline and a limited 2016 drilling program, a 1.2 Mmcfe/d decline due to non-core property sales, a 0.4 Mmcfe/d decline from downtime associated with the impact of Hurricane Harvey, and a 0.2 Mmcfe/d decline due to temporary pipeline limitations at the Vermillion 170 field. The decrease in production was partially offset by 2.6 Mmcfe/d of new production from drilling on our Southern Delaware Basin acreage. Net natural gas production for the year ended December 31, 2017 was approximately 38.1 Mmcf/d, compared with approximately 49.5 Mmcf/d for the year ended December 31, 2016. Net oil production declined from approximately 1,600 barrels per day to 1,400 barrels per day, while NGL production decreased from approximately 2,000 barrels per day to 1,400 barrels per day.

We reported revenues of approximately $78.2 million for the year ended December 31, 2016, compared to revenues of approximately $116.5 million for the year ended December 31, 2015. This decrease in revenues was primarily attributable to lower oil and natural gas prices in 2016 and lower production resulting from the significant reduction in our capital program because of the dramatic decline in, and uncertain outlook for, commodity prices.

Total production for the year ended December 31, 2016 was approximately 26.0 Bcfe, or 71.0 Mmcfe/d, compared to approximately 34.0 Bcfe, or 93.0 Mmcfe/d, in the prior year, a decline attributable in large part to our limited drilling activity in 2016 due to the low commodity price environment. Net natural gas production for the year ended December 31, 2016 was approximately 49.5 Mmcf/d, compared with approximately 61.9 Mmcf/d for the year ended December 31, 2015, due to normal decline in production from our offshore properties. Net oil production declined from approximately 2,500 barrels per day to 1,600 barrels per day, while NGL production decreased from approximately 2,600 barrels per day to 2,000 barrels per day. Both decreases were a result of the first half of 2015 including initial oil production from our new wells brought on production in Madison and Grimes counties of our Southeast Texas Region which were not offset by new production in 2016 due to a limited capital program.

Average Sales Prices

The average equivalent sales price realized for the years ended December 31, 2017, 2016 and 2015 was $3.90 per Mcfe, $3.01 per Mcfe and $3.43 per Mcfe, respectively. The price of natural gas for the years ended December 31, 2017, 2016 and 2015 was $2.97 per Mcf, $2.42 per Mcf and $2.61 per Mcf, respectively. The price for oil for the years ended December 31, 2017, 2016 and 2015 was $48.90 per barrel, $38.52 per barrel and $46.80 per barrel, respectively. The price for NGLs for the years ended December 31, 2017, 2016 and 2015 was $22.97 per barrel, $15.79 per barrel and $14.68 per barrel, respectively.

Operating Expenses (including production taxes)

Operating expenses for the year ended December 31, 2017 were approximately $27.2 million, or $1.35 per Mcfe, compared to approximately $29.1 million, or $1.12 per Mcfe, for the year ended December 31, 2016. Operating expenses for the year ended December 31, 2015 were approximately $37.8 million, or $1.11 per Mcfe. The table below provides additional detail of operating expenses for the years ended December 31, 2017, 2016 and 2015.

	Twelve Months Ended December 31,					
	2017		2016		2015	
	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)	(in thousands)	(per Mcfe)
Lease operating expenses	$ 17,458	$ 0.87	$ 18,608	$ 0.72	$ 25,124	$ 0.74
Production & ad valorem taxes	2,568	0.13	3,248	0.13	4,747	0.14
Transportation & processing costs	4,866	0.24	5,491	0.20	4,714	0.13
Workover costs	2,291	0.11	1,764	0.07	3,255	0.10
Total operating expenses	$ 27,183	$ 1.35	$ 29,111	$ 1.12	$ 37,840	$ 1.11

Production and ad valorem taxes decreased by 21% for the year ended December 31, 2017, compared to the year ended December 31, 2016, primarily as a result of property sales and lower legacy production, partially offset by production taxes on new West Texas production. Production and ad valorem taxes decreased by 32% for the year ended December 31, 2016, compared to the prior year, primarily due to the decrease in revenues for the same period.

Lease operating expenses decreased by 26% for the year ended December 31, 2016, compared to the year ended December 31, 2015, as a direct result of our efforts to reduce costs during the second half of 2015 and in 2016 in response to the challenging commodity price environment.

Exploration Expenses

We reported approximately $1.1 million and $1.8 million of exploration expenses for the years ended December 31, 2017 and 2016, respectively, which were primarily related to geological and geophysical software, seismic data licensing fees and mapping services. We reported approximately $12.0 million of exploration expenses for the year ended December 31, 2015, which included $6.7 million in dry-hole costs related to our State #1H well in Natrona County, Wyoming, and $2.8 million related to the early termination of a drilling rig contract.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the year ended December 31, 2017 was approximately $47.2 million, or $2.35 per Mcfe, compared to approximately $63.3 million, or $2.44 per Mcfe, for the year ended December 31, 2016, a decrease primarily attributable to lower production during 2017.

Depreciation, depletion and amortization for the year ended December 31, 2016 was approximately $63.3 million, or $2.44 per Mcfe, compared to approximately $133.4 million, or $3.93 per Mcfe, for the year ended December 31, 2015, a decrease primarily attributable to lower production during 2016. The rate decrease is primarily attributable to the impairment recorded in 2015.

Impairment and Abandonment of Oil and Gas Properties

Impairment and abandonment expenses for the year ended December 31, 2017 included proved property impairment of $0.3 million related to revised estimated reserves for our Tuscaloosa Marine Shale properties. Impairment expenses for the year ended December 31, 2017 also included a $1.5 million partial impairment of two unused offshore platforms in onshore storage.

Impairment and abandonment expenses for the year ended December 31, 2016 included proved property impairment of $0.7 million related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Impairment expenses for the year ended December 31, 2016 also included $6.8 million impairment related to our unproved properties in Fayette and Gonzales counties, Texas and $2.9 million related to our unproved acreage in Natrona County, Wyoming.

Impairment and abandonment expenses for the year ended December 31, 2015 included proved property impairment of $269.6 million related to the decline in commodity prices and the resulting impact on estimated future net cash flows from associated reserves. Approximately $235.8 million of the total proved property impairment for the year ended December 31, 2015 is attributable to the Madison/Grimes counties and Zavala/Dimmit/Karnes counties properties, our highest valued properties stemming from the Merger with Crimson. Impairment expenses for the year ended December 31, 2015 included a $16.3 million impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases. Approximately $9.3 million of the total for the year ended December 31, 2015 is related to unproved lease cost amortization of the Elm Hill project in Fayette and Gonzales counties, Texas.

General and Administrative Expenses

Total general and administrative expenses for the year ended December 31, 2017 were approximately $24.2 million, compared to $26.8 million for the year ended December 31, 2016. The decrease in general and administrative costs can primarily be attributed to lower bonus accruals for the 2017 performance period and lower professional fees, insurance expense and office costs during the year ended December 31, 2017. Included in our current year expense was approximately $6.1 million in non-cash stock based compensation. Included in the prior year expense was approximately $6.5 million in non-cash stock based compensation. Exclusive of the stock compensation, cash general and administrative expenses for the current year were $18.1 million, compared to cash expenses of $20.3 million for the prior year.

General and administrative expenses for the year ended December 31, 2016 were approximately $26.8 million, compared to $26.4 million for the year ended December 31, 2015. Included in the 2016 expense was approximately $6.5 million in non-cash stock based compensation. Included in the 2015 expense was approximately $0.6 million in cash severance costs resulting from an August 2015 reduction in force and $6.5 million in non-cash stock based compensation. Exclusive of the stock compensation and severance related costs, cash general and administrative expenses for the year ended December 30, 2016 were $20.3 million, compared to cash expenses of $19.3 million for the year ended December 31, 2015.

Gain (loss) from Affiliates

For the year ended December 31, 2017, the Company recorded a gain from affiliates of approximately $2.7 million, net of no tax expense, related to our equity investment in Exaro, compared with a gain from affiliates of approximately $1.5 million, net of no tax expense, for the year ended December 31, 2016.

For the year ended December 31, 2016, the Company recorded a gain from affiliates of approximately $1.5 million, net of no tax expense, related to our equity investment in Exaro, compared with a loss from affiliates of approximately $30.6 million, net of tax benefit of $16.5 million, for the year ended December 31, 2015.

Other Income (Expense)

Other income for the year ended December 31, 2017 was approximately $2.8 million, which consists of a $2.3 million gain on sale of assets, a $3.3 million net gain on derivatives, and a $1.3 million gain related to the sale of our investment in a small private service company. Other income was partially offset by interest expense of $4.1 million.

Other expense for the year ended December 31, 2016 was approximately $5.8 million, which is primarily related to interest expense of $3.8 million and loss on derivatives of $1.6 million.

Other expense for the year ended December 31, 2015 was approximately $0.7 million, which is primarily related to $5.6 million of costs incurred in pursuit of an unsuccessful acquisition in the fourth quarter and interest expense of $3.2 million, partially offset by $6.1 million in proceeds related to favorable outcomes in two lawsuits and gain on derivatives of $2.3 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 facility.

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,		
	2017	2016	2015
Net cash provided by operating activities	$ 34,686	$ 32,011	$ 24,955
Net cash used in investing activities	$ (65,450)	$ (19,798)	$ (76,806)
Net cash provided by (used in) financing activities	$ 30,764	$ (12,213)	$ 51,851
Cash and cash equivalents at the end of the period	$ —	$ —	$ —

Cash flow from operating activities, including changes in working capital, provided approximately $34.7 million in cash for the year ended December 31, 2017 compared to $32.0 million for the year ended December 31, 2016. The changes in working capital were approximately $5.1 million during 2017, compared to $7.8 million during 2016. Cash flow from operating activities, excluding changes in working capital, provided approximately $29.6 million in cash for the year ended December 31, 2017 compared to $24.2 million for the year ended December 31, 2016. This increase in cash provided by operating activities was primarily attributable to higher revenues associated with higher prices, partially offset by lower production.

Cash flow from operating activities, including changes in working capital, provided approximately $32.0 million in cash for the year ended December 31, 2016 compared to $25.0 million for the year ended December 31, 2015. The changes in working capital were approximately $7.8 million during 2016, compared to a deficit in 2015 of approximately $27.2 million. Cash flow from operating activities, excluding changes in working capital, provided approximately $24.2 million in cash for the year ended December 31, 2016 compared to $52.2 million for the year ended December 31, 2015. This decrease in cash provided by operating activities was primarily attributable to lower revenues associated with lower prices and lower production resulting from our reduced drilling activity in 2016 due to the low commodity price environment.

For the year ended December 31, 2017, we incurred $58.4 million in capital costs, primarily related to drilling and/or completing wells in the Southern Delaware Basin and acquiring or extending unproved leases. Of this amount, approximately $66.6 million was paid during the year, partially offset by $1.1 million primarily related to the sale of our assets in the North Bob West area and our operated assets in the Escobas area, both located in Southeast Texas, resulting in net cash used in investing activities of approximately $65.5 million for the year ended December 31, 2017.

For the year ended December 31, 2016, we incurred $39.0 million in capital costs, including $20.0 million for the acquisition of our Southern Delaware Basin acreage. Of this amount, approximately $24.9 million was paid during the year, partially offset by $5.1 million received for the sale of our Colorado properties, resulting in net cash used in investing activities of approximately $19.8 million for the year ended December 31, 2016.

For the year ended December 31, 2015, we incurred $55.6 million in capital costs. Of this amount, approximately $77.8 million was paid during the year, partially offset by approximately $1.0 million in distributions from REX as a result the dissolution of that entity, resulting in net cash used in in investing activities of approximately $76.8 million for the year ended December 31, 2015.

Cash provided by financing activities was approximately $30.8 million for the year ended December 31, 2017 compared to $12.2 million used in financing activities in 2016. The 2017 activity was primarily related to net borrowings under our RBC Credit Facility (defined below). The 2016 activity included net repayments of outstandings under our RBC Credit Facility.

Cash used in financing activities was approximately $12.2 million for the year ended December 31, 2016 compared to $51.9 million provided by financing activities in 2015. Included in 2016 activity was $50.4 million in proceeds from our equity offering to fund the acquisition and early development of our Southern Delaware Basin acreage and approximately $61.1 million in net repayments of outstandings under our RBC Credit Facility (defined below). 2015 activity included net borrowings under our RBC Credit Facility to reduce the working capital obligations at December 31, 2015.

Credit Facility

In October 2013, the Company entered into a four-year $500 million revolving credit facility with Royal Bank of Canada and other lenders (the "RBC Credit Facility"). In October 2016, the RBC Credit Facility was amended to, among other things, extend the maturity to October 1, 2019. The borrowing base under the facility is redetermined each November and May. Effective November 6, 2017, the borrowing base under the RBC Credit Facility was redetermined at $115 million.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require 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 RBC Credit Facility Agreement. Our compliance with these covenants is tested each quarter. At December 31, 2017, we were in compliance with all but the Current Ratio covenant under the RBC Credit Facility, although we obtained a waiver for such non-compliance. The RBC Credit Facility 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, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events. See Note 12 to our Financial Statements -"Long-Term Debt" for a more detailed description of terms and provisions of our credit agreement.

Future Capital Requirements

Our future crude 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 intend to grow our reserves and production by further exploiting our existing property base through drilling opportunities in our resource plays and in our conventional onshore inventory in West Texas and the Texas Gulf Coast, with activity in any particular area and period of time to be a function of market and field economics. 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 RBC Credit Facility 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 2018 capital budget will be focused primarily on the Southern Delaware Basin, while at the same time: (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 current capital budget for 2018 should allow us to meet our contractual requirements, remain in position to preserve our term acreage where appropriate and maintain a healthy financial profile during this challenging period for our industry. We will continuously monitor the commodity price environment, 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, 2017, we paid approximately $0.6 million in state income taxes and no federal income taxes. During the year ended December 31, 2016, we received a refund of approximately $2.1 million in federal and state income taxes. During the year ended December 31, 2015 we received a refund of approximately $0.2 million in federal and state income taxes.

Contractual Obligations

The following table summarizes our known contractual obligations as of December 31, 2017:

	Payment due by period (thousands)				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long term debt and interest (1)	$ 93,118	$ 4,427	$ 88,691	$ —	$ —
Delay rentals	490	83	163	163	81
Asset retirement obligations	22,405	2,017	1,502	1,562	17,324
Employment agreements	2,476	1,559	917	—	—
Operating leases (2)	3,705	3,070	635	—	—
Hardware/software	561	390	163	8	—
Uncertain income tax positions	227	—	227	—	—
Total	$122,982	$11,546	$ 92,298	$ 1,733	$ 17,405

(1) Estimated interest is based on the outstanding debt at December 31, 2017 using the interest rate in effect at that time.

(2) Operating leases include contracts related to office space, compressors, vehicles, office equipment and other.

In addition to the above, we have a throughput agreement with a third party pipeline owner/operator through March 2020. See Note 13 to our Financial Statements – "Commitments and Contingencies" for further information.

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 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, 2017 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $0.6 million, $1.2 million and $1.9 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, such as the current low commodity price environment, 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. Assuming strip pricing as of March 1, 2018 through 2022 and keeping pricing flat thereafter, instead of 2017 SEC pricing, while leaving all other parameters unchanged, the Company's proved reserves would have been 188.6 Bcfe and the PV-10 value of proved reserves would have been $258.3 million.

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, 2017, we had federal net operating loss (“NOL”) carryforwards of $284.4 million which occurred due to the Merger, and subsequent taxable losses in 2014, 2015, 2016 and 2017 due to lower commodity prices and impairment of oil and gas property. 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. Given the uncertainty of our ability to generate taxable income, a valuation allowance of $49.0 million has been recorded for the year ended December 31, 2017 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 15 - "Income Taxes” to our consolidated financial statements.

Recent Accounting Pronouncements

In January 2017, the FASB issued ASU No. 2017-01: Business Combinations (Topic 805) Clarifying the Definition of a Business (ASU 2017-01). The amendments in this update are intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. Public business entities should apply the amendments in this update to annual periods beginning after December 15, 2017, including interim periods within those periods. The amendments in this update should be applied prospectively on or after the effective date. No disclosures are required at transition. The provisions of this accounting update are not expected to have a material impact on the Company’s financial position or results of operations.

In August 2016, the FASB issued ASU No. 2016-15: Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments. The main objective of this update is to reduce the diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. This update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The eight cash flow updates relate to the following issues: 1) debt prepayment or debt extinguishment costs; 2) settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; 3) contingent consideration payments made after a business combination; 4) proceeds from the settlement of insurance claims; 5) proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies; 6) distributions received from equity method investees; 7) beneficial interest in securitization transactions; and 8) separately identifiable cash flows and application of the predominance principle. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The provisions of this accounting update are not expected to have a material impact on the Company’s presentation of cash flows.

In February 2016, the FASB issued ASU No. 2016-02: Leases (Topic 842) (ASU 2016-02). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize assets and liabilities arising from leases on the balance sheet. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Company will continue to assess the impact this may have on its financial position, results of operations, and cash flows.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Several additional standards related to revenue recognition have been issued that amend the original standard, with most providing additional clarification.

In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 by one year. This new standard is now effective for annual reporting periods beginning after December 15, 2017, and the Company has completed the assessment of this standard. The impact on the Company's financial statements is not material, and there is no material impact expected to opening retained earnings. The standard was adopted January 1, 2018 using the modified retrospective method. Certain items netted in revenue or recorded as expense prior to adoption have changed based on the requirements of the new ASU using the control model and the definitions of parties to the contract as principal or agent. The company implemented processes to ensure new contracts are reviewed for the appropriate accounting treatment and additional disclosures will be required in our Form 10-Q for the three months ended March 31, 2018.

Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of December 31, 2017, the primary off-balance sheet arrangements that we have entered into included 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 arrangements shown under operating leases and drilling rig in the commitments and contingencies table, we have no other arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

Item 7A. *Quantitative and Qualitative Disclosure about Market Risk*

Commodity Risk

We are exposed to various risks including energy commodity price risk for our oil, natural gas and natural gas liquids production. When oil, natural gas and natural gas liquids prices decline significantly our ability to finance our capital budget and operations may be adversely impacted. Our major commodity price risk exposure is to the prices received for oil, natural gas and natural gas liquids produced and sold. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for oil, natural gas and natural gas liquids are volatile and unpredictable. For the year ended December 31, 2017, a 10% fluctuation in the prices received for oil, natural gas and natural gas liquids production would have had an approximate $7.9 million impact on our revenues.

Derivative Instruments and Hedging Activity

We expect commodity prices to remain volatile and unpredictable, therefore we have designed a risk management strategy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include swaps and costless collars. The total volumes which we hedge through the use of our derivative instruments varies from period to period. As of December 31, 2017, we had the following financial derivative contracts in place:

Commodity	Period	Derivative	Volume/Month		Price/Unit
Natural Gas	Jan 2018 - July 2018	Swap	370,000 MMBtus	$	3.07 (1)
Natural Gas	Aug 2018 - Oct 2018	Swap	70,000 MMBtus	$	3.07 (1)
Natural Gas	Nov 2018 - Dec 2018	Swap	320,000 MMBtus	$	3.07 (1)
Oil	Jan 2018 - June 2018	Swap	20,000 Bbls	$	56.40 (2)
Oil	July 2018 - Oct 2018	Collar	20,000 Bbls	$	52.00 - 56.85 (2)
Oil	Nov 2018 - Dec 2018	Collar	15,000 Bbls	$	52.00 - 56.85 (2)
Oil	Jan 2018 - Dec 2018	Collar	2,000 Bbls	$	52.00 - 58.76 (3)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$	50.00 - 58.00 (2)

In January 2018, we entered into the following additional derivative contracts with members of our bank group:

Commodity	Period	Derivative	Volume/Month		Price/Unit
Oil	Jan 2018 - July 2018	Collar	6,000 Bbls	$	58.00 - 68.00 (2)
Oil	Nov 2018 - Dec 2018	Collar	5,000 Bbls	$	58.00 - 68.00 (2)
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$	52.00 - 59.45 (3)

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

(2) Based on Arugs Louisiana Light Sweet crude oil prices.

(3) Based on West Texas Intermediate crude oil prices.

Our hedge strategy and objectives may change significantly as our operational profile changes and/or commodities prices change.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy institutions deemed by management as competent and competitive market makers. The counterparties to the Company's current and previous derivative contracts are large financial institutions and also lenders or affiliates of lenders in our RBC Credit Facility. We do not post collateral under any of these contracts as they are secured under our RBC Credit Facility. See Note 6 to our Financial Statements - "Derivative Instruments" for additional information.

We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, (“ASC 815”). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. The estimated fair values for financial instruments under ASC 825, Financial Instruments (“ASC 825”) are 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, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Note 6 to our Financial Statements - "Derivative Instruments" for more details.

Interest Rate Sensitivity

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and the U.S. prime rate based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

As of December 31, 2017, our total long-term debt was $85.4 million, which bears interest at a floating or market interest rate that is tied to the prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. During the year ended December 31, 2017 our effective rate fluctuated between 4.0 percent and 7.8 percent, depending on the term of the specific debt drawdowns. At December 31, 2017, we did not have any outstanding interest rate swap agreements. As of December 31, 2017, the weighted average interest rate on our variable rate debt was 5.2% per year. Assuming our current level of borrowings, a 100 basis point increase in the interest rates we pay under our RBC Credit Facility would result in an increase of our interest expense by $0.9 million for a twelve month period.

Other Financial Instruments

As of December 31, 2017, we had no cash or cash equivalents. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments to hedge any changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we may invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings. Based on a sensitivity analysis performed on the financial instruments held as of December 31, 2017, an immediate 10% change in interest rates is not expected to have a material effect on our near-term financial condition or results of operations.

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-36 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 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, 2017, 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 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

There was no change in our internal controls over financial reporting during the fiscal quarter ended December 31, 2017 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, 2017.

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, 2017, as stated in their report which is 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 Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2017, and our report dated March 9, 2018 expressed an unqualified opinion on those financial statements.

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

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

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

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

/ s / GRANT THORNTON LLP

Houston, Texas
March 9, 2018

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 2018 Annual Meeting of Stockholders (the "Proxy Statement") under the headings "Proposal 1: Election of Directors", "Executive Compensation", "Section 16(a) Beneficial Ownership Reporting Compliance" 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, 2017.

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***

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

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 crude 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 crude 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 crude 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 crude 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.

MBbls. Thousand barrels of crude 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 crude oil, condensate or natural gas liquids.

MMBbls. million barrels of crude 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 crude 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 crude 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 crude 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 crude 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.

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. 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).
3.1	Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.1 to the Company's report on Form 8-K, dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000, and incorporated by reference herein).
3.2	Third Amended and Restated Bylaws of Contango Oil & Gas Company (filed as Exhibit 3.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2015, as filed with the Securities and Exchange Commission on March 3, 2015, and incorporated by reference herein).
3.3	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company (filed as Exhibit 3.4 to the Company's report on Form 10-QSB for the quarter ended December 31, 2002, dated November 14, 2002, as filed with the Securities and Exchange Commission, 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).
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 (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	Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 9, 2008 between Contango Offshore Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.48 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).
10.5	Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 7, 2009 between Contango Offshore Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.49 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).

Exhibit Number	Description
10.6	Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of January 29, 2010 between Contango Offshore Exploration LLC and Contango Operators, Inc. (filed as Exhibit 10.50 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	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).
10.8	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).
10.9	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).
10.10	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).
10.11*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and Allan D. Keel (filed as Exhibit 10.11 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).
10.12*	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).
10.13*	Amendment and Extension of Employment Agreement, dated as of October 10, 2016, among Contango Oil & Gas Company and A. Carl Isaac (filed as Exhibit 10.3 to the Company's report on Form 8-K dated as of October 10, 2016, as filed with the Securities and Exchange Commission on October 14, 2016, and incorporated by reference herein).
10.14*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and Jay S. Mengle (filed as Exhibit 10.17 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).
10.15*	Amended and Restated Employment Agreement, dated as of November 30, 2016, among Contango Oil & Gas Company and Thomas H. Atkins (filed as Exhibit 10.18 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).
10.16	Participation Agreement covering Timbalier Island Prospect, South Timbalier Area Block 17, S.L. 21906, dated April 3, 2013 between Republic Exploration LLC, Juneau Exploration, L.P. and Contango Operators, Inc. (filed as Exhibit 10.81 to the Company's report on Form 10-K for the fiscal year ended June 30, 2013, as filed with the Securities and Exchange Commission on August 29, 2013, and incorporated by reference herein).
10.17	Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto dated October 1, 2013 (filed as Exhibit 10.1 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).

Exhibit Number	Description
10.18	First Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.1 to the Company's report on Form 8-K dated as of April 11, 2014, as filed with the Securities and Exchange Commission on April 15, 2014, and incorporated by reference herein).
10.19	Second Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.1 to the Company's report on Form 8-K dated as of October 28, 2014, as filed with the Securities and Exchange Commission on October 31, 2014, and incorporated by reference herein).
10.20	Third Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto (filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended March 31, 2016, as filed with the Securities and Exchange Commission on May 9, 2016, and incorporated by reference herein).
10.21	Fourth Amendment to Credit Agreement among Contango Oil & Gas Company, as Borrower, Royal Bank of Canada, as Administrative Agent, and the Lenders Signatory Hereto. †
10.22*	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).
10.23	Liquidation Agreement between Juneau Exploration LP, Contango Operators, Inc. and Fairfield Industries Incorporated, dated December 31, 2016 (filed as Exhibit 10.27 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).
10.24*	Employment Agreement, dated as of February 26, 2017, among Contango Oil & Gas Company and James J. Metcalf Jr. (filed as Exhibit 10.28 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).
10.25*	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).
10.26*	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).
21.1	List of Subsidiaries. †
21.2	Organizational Chart. †
23.1	Consent of William M. Cobb & Associates, Inc. †
23.2	Consent of Netherland, Sewell & Associates, Inc. †
23.3	Consent of W.D. Von Gonten & Co. †
23.4	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 Netherland, Sewell & Associates. †
99.3	Report of W.D. Von Gonten and Company. †

* Indicates a management contract or compensatory plan or arrangement

† Filed herewith

SIGNATURES

In accordance with 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/ ALLAN D. KEEL Date: March 9, 2018

Allan D. Keel

Chief Executive Officer

POWER OF ATTORNEY

Know all men by these presents, that the undersigned constitutes and appoints Allan D. Keel 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.

In accordance with 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/ ALLAN D. KEEL Allan D. Keel	Chief Executive Officer (principal executive officer) and Director	March 9, 2018
/s/ E. JOSEPH GRADY E. Joseph Grady	Chief Financial Officer (principal financial officer)	March 9, 2018
/s/ DENISE DUBARD Denise DuBard	Chief Accounting Officer (principal accounting officer)	March 9, 2018
/s/ JOSEPH J. ROMANO Joseph J. Romano	Director	March 9, 2018
/s/ B. A. BERILGEN B. A. Berilgen	Director	March 9, 2018
/s/ B. JAMES FORD B. James Ford	Director	March 9, 2018
/s/ ELLIS L. MCCAIN Ellis L. McCain	Director	March 9, 2018
/s/ CHARLES M. REIMER Charles M. Reimer	Director	March 9, 2018

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 Delaware corporation) and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, cash flows, and shareholders' equity for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 9, 2018 expressed an unqualified opinion.

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 9, 2018

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

	December 31, 2017	December 31, 2016
CURRENT ASSETS:		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net	13,059	16,727
Prepaid expenses	1,892	1,787
Current derivative asset	822	—
Inventory	—	540
Total current assets	15,773	19,054
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	1,239,662	1,188,065
Unproved properties	35,243	38,338
Other property and equipment	1,272	1,265
Accumulated depreciation, depletion and amortization	(930,220)	(887,286)
Total property, plant and equipment, net	345,957	340,382
OTHER NON-CURRENT ASSETS:		
Investments in affiliates	18,464	15,767
Deferred tax asset	424	—
Other	835	1,311
Total other non-current assets	19,723	17,078
TOTAL ASSETS	$ 381,453	$ 376,514
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 46,755	$ 55,135
Current derivative liability	1,765	3,446
Current asset retirement obligations	2,017	4,308
Total current liabilities	50,537	62,889
NON-CURRENT LIABILITIES:		
Long-term debt	85,380	54,354
Long-term derivative liability	300	—
Asset retirement obligations	20,388	22,618
Other long term liabilities	248	248
Total non-current liabilities	106,316	77,220
Total liabilities	156,853	140,109
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 30,873,470 shares issued and 25,505,715 shares outstanding at December 31, 2017, 30,557,987 shares issued and 25,238,600 shares outstanding at December 31, 2016	1,223	1,211
Additional paid-in capital	302,527	296,439
Treasury shares at cost (5,367,755 shares at December 31, 2017 and 5,319,387 shares at December 31, 2016)	(128,583)	(128,321)
Retained earnings	49,433	67,076
Total shareholders' equity	224,600	236,405
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 381,453	$ 376,514

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,		
	2017	**2016**	**2015**
REVENUES:			
Oil and condensate sales	$ 25,347	$ 23,006	$ 43,230
Natural gas sales	41,317	43,847	59,058
Natural gas liquids sales	11,881	11,330	14,217
Total revenues	78,545	78,183	116,505
EXPENSES:			
Operating expenses	27,183	29,111	37,840
Exploration expenses	1,106	1,816	11,979
Depreciation, depletion and amortization	47,215	63,323	133,380
Impairment and abandonment of oil and gas properties	2,395	10,572	285,877
General and administrative expenses	24,161	26,802	26,402
Total expenses	102,060	131,624	495,478
OTHER INCOME (EXPENSE):			
Gain (loss) from investment in affiliates (net of income taxes)	2,697	1,545	(30,582)
Interest expense	(4,100)	(3,802)	(3,164)
Gain (loss) on derivatives, net	3,325	(1,632)	2,348
Other income (expense)	3,555	(357)	97
Total other income (expense)	5,477	(4,246)	(31,301)
NET LOSS BEFORE INCOME TAXES	(18,038)	(57,687)	(410,274)
Income tax benefit (provision)	395	(342)	75,226
NET LOSS ATTRIBUTABLE TO COMMON STOCK	$ (17,643)	$ (58,029)	$ (335,048)
NET LOSS PER SHARE:			
Basic	$ (0.71)	$ (2.71)	$ (17.67)
Diluted	$ (0.71)	$ (2.71)	$ (17.67)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	24,686	21,424	18,965
Diluted	24,686	21,424	18,965

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,		
	2017	**2016**	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	(17,643)	(58,029)	(335,048)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	47,215	63,323	133,380
Impairment of natural gas and oil properties	1,785	10,438	285,870
Exploration expenses (recovery)	(232)	(1)	6,494
Deferred income taxes	(424)	—	(92,329)
Loss (gain) on sale of assets	(2,321)	92	231
Loss (gain) from investment in affiliates	(2,697)	(1,545)	47,049
Stock-based compensation	6,100	6,457	6,516
Unrealized loss (gain) on derivative instruments	(2,204)	3,446	—
Changes in operating assets and liabilities:			
Decrease in accounts receivable & other	3,914	1,006	4,261
Decrease (increase) in prepaid expenses	(105)	(560)	714
Increase (decrease) in accounts payable & advances from joint owners	450	2,116	(28,672)
Increase (decrease) in other accrued liabilities	1,353	2,436	(5,711)
Decrease (increase) in income taxes receivable, net	(332)	2,777	405
Increase (decrease) in income taxes payable, net	(252)	(187)	481
Other	79	242	1,314
Net cash provided by operating activities	$ 34,686	$ 32,011	$ 24,955
CASH FLOWS FROM INVESTING ACTIVITIES:			
Natural gas and oil exploration and development expenditures	$ (66,613)	$ (24,929)	$ (77,820)
Sale of oil and gas properties	1,151	5,120	—
Sale of furniture and equipment	12	11	—
Return of investment in affiliates	—	—	1,014
Net cash used in investing activities	$ (65,450)	$ (19,798)	$ (76,806)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	$ 239,514	$ 148,881	$ 356,102
Repayments under credit facility	(208,488)	(209,972)	(304,016)
Net proceeds from equity offering	—	50,435	—
Purchase of treasury stock	(262)	(561)	(235)
Debt issuance costs	—	(996)	—
Net cash provided by (used in) financing activities	$ 30,764	$ (12,213)	$ 51,851
NET DECREASE IN CASH AND CASH EQUIVALENTS	$ —	$ —	$ —
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	—	—	—
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ —	$ —	$ —

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(in thousands, expect share amounts)

	Common Stock		Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
	Shares	Amount				
Balance at December 31, 2014	19,148,000	$ 963	$ 233,278	$ (127,525)	$ 460,750	$ 567,466
Treasury shares at cost	(31,252)	—	—	(235)	—	(235)
Restricted shares activity	264,398	11	(10)	—	—	1
Stock-based compensation	—	—	6,256	—	—	6,256
Dissolution of REX	—	—	—	—	(597)	(597)
Net loss	—	—	—	—	(335,048)	(335,048)
Balance at December 31, 2015	19,381,146	$ 974	$ 239,524	$ (127,760)	$ 125,105	$ 237,843
Equity Offering	5,360,000	214	50,221	—	—	50,435
Treasury shares at cost	(63,597)	—	—	(561)	—	(561)
Restricted shares activity	561,051	23	(22)	—	—	1
Stock-based compensation	—	—	6,716	—	—	6,716
Net loss	—	—	—	—	(58,029)	(58,029)
Balance at December 31, 2016	25,238,600	$ 1,211	$ 296,439	$ (128,321)	$ 67,076	$ 236,405
Treasury shares at cost	(48,368)	—	—	(262)	—	(262)
Restricted shares activity	315,483	12	(12)	—	—	—
Stock-based compensation	—	—	6,100	—	—	6,100
Net loss	—	—	—	—	(17,643)	(17,643)
Balance at December 31, 2017	25,505,715	$ 1,223	$ 302,527	$ (128,583)	$ 49,433	$ 224,600

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. 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 properties in Texas and Wyoming and to use that cash flow to explore, develop, exploit, increase production from and acquire crude oil and natural gas properties in onshore West Texas, the Texas Gulf Coast and the Rocky Mountain regions of the United States.

On October 1, 2013, the Company completed a merger with Crimson Exploration Inc. ("Crimson") (the “Merger”). The Company historically focused operations in the GOM, but the Merger has given the Company access to high rate of return onshore prospects in known, prolific producing areas as well as long-life resource plays. Beginning in the second half of 2015, the Company reduced its drilling program in response to the challenging commodity price environment, and instead focused on: (i) the preservation of its strong and flexible financial position, including limiting its overall capital expenditure budget to internally generated cash flow; (ii) the identification of opportunities for cost and production efficiencies in all areas of its operations; and (iii) maintaining core leases and continuing to identify new resource potential opportunities internally and, where appropriate, through acquisition. As a result, until the latter half of 2016, the Company’s only drilling activity was in Weston County, Wyoming, where it completed its third well targeting the Muddy Sandstone formation. During the third quarter of 2016, the Company acquired acreage in the Southern Delaware Basin in Pecos County, Texas (the “Acquisition”), and as of December 31, 2017, had increased its acreage in the Southern Delaware Basin to 16,500 gross acres (6,800 net). Since the Acquisition, the Company has begun production from seven wells in the Southern Delaware Basin and is waiting on completion of an eighth well. The Company currently expects that the Southern Delaware Basin position will continue to be the primary focus of its drilling program for 2018.

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. On December 30, 2016, the Company completed the sale of all of its Colorado assets, primarily located in the Adams and Weld counties.

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. Oil and gas exploration and development affiliates which are not controlled by the Company, such as Republic Exploration LLC (“REX”), are proportionately consolidated. REX was dissolved as of December 31, 2015.

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 and gas revenues, income taxes, stock-based compensation, reserve estimates, impairment of natural gas and oil properties, valuation of derivatives and accrued liabilities. Actual results could differ from those estimates.

Revenue Recognition

Revenues from the sale of natural gas and oil produced are recognized upon the passage of title, net of royalties. Revenues from natural gas production are recorded using the sales method. When sales volumes exceed the Company's entitled share, 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. As of December 31, 2017, 2016 and 2015, the Company had no significant imbalances.

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, 2017, the Company had no cash and cash equivalents, as cash balances at the end of each day are transferred to reduce outstanding debt under the Company's revolving credit facility 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, 2017, accounts payable included $2.3 million in outstanding checks that had not been presented for payment. At December 31, 2016, accounts payable included $3.5 million in outstanding checks that had not been presented for payment.

Accounts Receivable

The Company sells natural gas and crude oil to a limited number of customers. In addition, the Company participates with other parties in the operation of natural gas and crude oil wells. Substantially all of the Company's accounts receivables are due from either purchasers of natural gas and crude oil or participants in natural gas and crude oil wells for which the Company serves as the operator. Generally, operators of natural gas and crude 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 $0.8 and $0.7 million as of December 31, 2017 and 2016, respectively. At December 31, 2017 and 2016, 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 crude 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 crude 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

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 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. For the year ended December 31, 2017, the Company recorded an impairment expense of approximately $0.3 million related to proved properties. For the year ended December 31, 2016, the Company recorded an impairment expense of approximately $0.7 million related to proved properties. For the year ended December 31, 2015, the Company recorded an impairment expense of approximately $269.6 million related to proved properties. Approximately $235.8 million of this amount was attributable to the Madison/Grimes counties and Zavala/Dimmit/Karnes counties properties.

Unproved properties are reviewed quarterly to determine if there has been an impairment of the carrying value, and any such impairment is charged to expense in the period. During the year ended December 31, 2017, the Company recognized impairment expense of approximately $1.5 million related to the partial impairment of two unused offshore platforms in onshore storage. During the year ended December 31, 2016, the Company recognized impairment expense of approximately $6.8 million related to unproved properties in Fayette and Gonzales counties, Texas and $2.9 million related to unproved acreage in Natrona County, Wyoming. During the year ended December 31, 2015, the Company recognized impairment expense of approximately $16.3 million related to impairment and partial impairment of certain unproved properties and onshore prospects due primarily to the sustained low commodity price environment and expiring leases. Approximately $9.3 million of this amount related to unproved lease cost amortization of properties in Fayette and Gonzales counties, Texas.

Asset Retirement Obligations

ASC 410, 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 11 - "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, 2017. The amount of unrecognized tax benefits did not materially change from December 31, 2016. 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 1998 – 2016, and state tax returns for 2010 – 2016, 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, 2013, the Company initially incurred $2.2 million of debt issuance costs relating to the new RBC credit facility entered into in conjunction with the Merger with Crimson. The debt issuance costs were to be amortized over the original four year term of the credit line. In connection with RBC Credit Facility amendment in May 2016, the Company incurred an additional $1.0 million of debt issuance costs. As of December 31, 2017, the remaining balance of these debt issuance costs was $0.8 million, which will be amortized through October 1, 2019, with amortization expense included in the DD&A line item in the Company's income statement for the years ended December 31, 2017, 2016 and 2015.

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 primarily consists of casing and tubing 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 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, 2017, 2016 and 2015. 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.

Recent Accounting Pronouncements

In January 2017, the FASB issued ASU No. 2017-01: Business Combinations (Topic 805) Clarifying the Definition of a Business (ASU 2017-01). The amendments in this update are intended to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. Public business entities should apply the amendments in this update to annual periods beginning after December 15, 2017, including interim periods within those periods. The amendments in this update should be applied prospectively on or after the effective date. No disclosures are required at transition. The provisions of this accounting update are not expected to have a material impact on the Company's financial position or results of operations.

In August 2016, the FASB issued ASU No. 2016-15: Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments. The main objective of this update is to reduce the diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. This update addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice. The eight cash flow updates relate to the following issues: 1) debt prepayment or debt extinguishment costs; 2) settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; 3) contingent consideration payments made after a business combination; 4) proceeds from the settlement of insurance claims; 5) proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies; 6) distributions received from equity method investees; 7) beneficial interest in securitization transactions; and 8) separately identifiable cash flows and application of the predominance principle. The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The provisions of this accounting update are not expected to have a material impact on the Company's presentation of cash flows.

In February 2016, the FASB issued ASU No. 2016-02: Leases (Topic 842) (ASU 2016-02). The main objective of ASU 2016-02 is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires lessees to recognize assets and liabilities arising from leases on the balance sheet. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. For public entities, ASU 2016-02 is effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years; early application is permitted. The Company will continue to assess the impact this may have on its financial position, results of operations, and cash flows.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Several additional standards related to revenue recognition have been issued that amend the original standard, with most providing additional clarification.

In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 by one year. This new standard is now effective for annual reporting periods beginning after December 15, 2017, and the Company has completed the assessment of this standard. The impact on the Company's financial statements is not material, and there is no material impact expected to opening retained earnings. The standard was adopted January 1, 2018 using the modified retrospective method. Certain items netted in revenue or recorded as expense prior to adoption have changed based on the requirements of the new ASU using the control model and the definitions of parties to the contract as principal or agent. The company implemented processes to ensure new contracts are reviewed for the appropriate accounting treatment and additional disclosures will be required in our Form 10-Q for the three months ended March 31, 2018.

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, 2017 was ConocoPhillips Company (51.2%). The Company's sales to this company is 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, Dispositions and Gains from Affiliates

Southern Delaware Basin Acquisition

In July 2016, the Company purchased one-half of the seller's interest in approximately 12,100 gross undeveloped acres (approximately 5,000 net acres) in the Southern Delaware Basin of Texas (the "Acquisition") for up to $25 million. The purchase price was comprised of $10 million in cash paid on July 26, 2016, plus $10 million to be paid in the form of carried well costs expected to be paid over the period of drilling and completing the first six wells. Additionally, contingent upon success, $5 million in spud bonuses is to be paid by the Company ratably over the following 14 wells drilled, which would increase the total consideration paid by the Company to $25 million. As of December 31, 2017, the Company had paid all $10 million of the carried well costs and $1.1 million in spud bonuses. As of December 31, 2017, the Company has increased its acreage to approximately 16,500 gross operated acres (6,800 net).

Colorado Property Sale

On December 30, 2016, all of the Company's non-core Colorado assets were sold to an independent oil and gas company for an aggregate purchase price of $5.0 million, subject to normal post-closing adjustments. The properties consisted of the Company's approximately 16,000 gross (11,200 net) acres primarily in Adams and Weld counties, Colorado and associated producing vertical wells.

North Bob West Property Sale

Effective February 1, 2017, the Company sold to a third party all of its assets in the North Bob West area and its operated assets in the Escobas area, both located in Southeast Texas, for a cash purchase price of $650,000. The Company recorded a net gain of $2.9 million after removal of the asset retirement obligations associated with the sold properties.

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, 2017, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which were believed to have a minimal credit risk. 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 counterparties to the Company's current and previous derivative contracts are lenders in the Company's RBC Credit Facility. The Company did not post collateral under any of these contracts as they were secured under the RBC Credit Facility.

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 RBC Credit Facility approximates carrying value because the interest rate approximates current market rates and are re-set at least every three months. See Note 12 - "Long-Term Debt" for further information.

Fair value estimates used for non-financial assets are evaluated at fair value on a non-recurring basis 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 crude 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, 2017, 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 crude 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 counterparties to the Company's current and previous derivative contracts are lenders or affiliates of lenders in the RBC Credit Facility. The Company does not post collateral under any of these contracts as they are secured under the RBC Credit Facility.

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 had the following financial derivative contracts in place as of December 31, 2017:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Natural Gas	Jan 2018 - July 2018	Swap	370,000 MMBtus	$ 3.07 (1)
Natural Gas	Aug 2018 - Oct 2018	Swap	70,000 MMBtus	$ 3.07 (1)
Natural Gas	Nov 2018 - Dec 2018	Swap	320,000 MMBtus	$ 3.07 (1)
Oil	Jan 2018 - June 2018	Swap	20,000 Bbls	$ 56.40 (2)
Oil	July 2018 - Oct 2018	Collar	20,000 Bbls	$ 52.00 - 56.85 (2)
Oil	Nov 2018 - Dec 2018	Collar	15,000 Bbls	$ 52.00 - 56.85 (2)
Oil	Jan 2018 - Dec 2018	Collar	2,000 Bbls	$ 52.00 - 58.76 (3)
Oil	Jan 2019 - Dec 2019	Collar	7,000 Bbls	$ 50.00 - 58.00 (2)

Additionally, in January 2018, the Company entered into the following additional derivative contracts with members of its bank group:

Commodity	Period	Derivative	Volume/Month	Price/Unit
Oil	Jan 2018 - July 2018	Collar	6,000 Bbls	$ 58.00 - 68.00 (2)
Oil	Nov 2018 - Dec 2018	Collar	5,000 Bbls	$ 58.00 - 68.00 (2)
Oil	Jan 2019 - Dec 2019	Collar	4,000 Bbls	$ 52.00 - 59.45 (3)

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

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

(3) Based on West Texas Intermediate crude oil prices.

The Company had the following financial derivative contracts in place as of December 31, 2016:

Commodity	Period	Derivative	Volume/Month	Price/Unit (1)
Natural Gas	Jan 2017 - July 2017	Collar	400,000 MMBtus	$ 2.65 - 3.00
Natural Gas	Aug 2017 - Oct 2017	Collar	200,000 MMBtus	$ 2.65 - 3.00
Natural Gas	Nov 2017 - Dec 2017	Collar	400,000 MMBtus	$ 2.65 - 3.00
Natural Gas	Jan 2017 - July 2017	Swap	300,000 MMBtus	$ 3.51
Natural Gas	Aug 2017 - Oct 2017	Swap	70,000 MMBtus	$ 3.51
Natural Gas	Nov 2017 - Dec 2017	Swap	300,000 MMBtus	$ 3.51
Oil	Jan 2017 - July 2017	Swap	9,000 Bbls	$ 53.95
Oil	Aug 2017 - Oct 2017	Swap	6,000 Bbls	$ 53.95
Oil	Nov 2017 - Dec 2017	Swap	8,000 Bbls	$ 53.95
Oil	Jan 2017 - Dec 2017	Swap	9,000 Bbls	$ 56.20

(1) Commodity price derivatives are based on Henry Hub NYMEX natural gas prices and West Texas Intermediate oil prices, as applicable.

There were no derivative contracts in place as of December 31, 2015.

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2017 (in thousands).

	Gross	Netting [(1)]	Total
Assets	$ 1,188	$ (1,188)	$ —
Liabilities	$ (2,431)	$ 1,188	$ (1,243)

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

The following summarizes the fair value of commodity derivatives outstanding on a gross and net basis as of December 31, 2016 (in thousands):

	Gross	Netting [(1)]	Total
Assets	$ —	$ —	$ —
Liabilities	$ (3,446)	$ —	$ (3,446)

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

The following table summarizes the effect of derivative contracts on the Consolidated Statements of Operations for the years ended December 31, 2017, 2016 and 2015 (in thousands):

	Year Ended December 31,		
Contract Type	**2017**	**2016**	**2015**
Crude oil contracts	$ 861	$ 1,814	$ 2,348
Natural gas contracts	260	—	—
Realized gain	$ 1,121	$ 1,814	$ 2,348
Crude oil contracts	$ (2,065)	$ —	$ —
Natural gas contracts	4,269	(3,446)	—
Unrealized gain (loss)	$ 2,204	$ (3,446)	$ —
Gain (loss) on derivatives, net	$ 3,325	$ (1,632)	$ 2,348

7. Stock Based Compensation

As of December 31, 2017, the Company had in place the Contango Oil & Gas Company Amended and Restated 2009 Incentive Compensation Plan ("the 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.

Amended and Restated 2009 Incentive Compensation Plan

On April 10, 2014, the Company's board of directors (the "Board") amended and restated the Company's then existing incentive compensation plan through the adoption of the 2009 Plan. The 2009 Plan provides for both cash awards and equity awards to officers, directors, employees or consultants of the Company. Awards made under the 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 2009 Plan, shares of the Company's common stock may be issued for plan awards. Stock options under the 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, 2017, the Company had approximately 1.6 million shares of equity awards available for future grant under the 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 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. This plan expired on February 25, 2015, and therefore, no additional shares are available for grant.

Stock Options

During the years ended December 31, 2017, 2016 and 2015, the Company did not issue any stock options.

A summary of stock options as of and for the years ended December 31, 2017, 2016 and 2015 is presented in the table below (dollars in thousands, except per share data):

	Year Ended December 31,					
	2017		2016		2015	
	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price
Outstanding, beginning of the period	111,905	$ 55.53	116,461	$ 55.03	129,934	$ 53.85
Exercised	—	$ —	—	$ —	—	$ —
Expired / Forfeited	(17,072)	$ 43.50	(4,556)	$ 42.92	(13,473)	$ 43.65
Outstanding, end of year	94,833	$ 57.69	111,905	$ 55.53	116,461	$ 55.03
Aggregate intrinsic value	$ —		$ —		$ —	
Exercisable, end of year	94,833	$ 57.69	111,905	$ 55.53	116,461	$ 55.03
Aggregate intrinsic value	$ —		$ —		$ —	
Available for grant, end of the period*	2,002,492		323,172		885,449	
Weighted average fair value of options granted during the period	$ —		$ —		$ —	

* Excludes Performance Stock Units.

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, 2017, 2016 and 2015, 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, 2017, 2016 and 2015, 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, 2017, 2016 and 2015 was zero.

Restricted Stock

During the year ended December 31, 2017, the Company issued 383,376 restricted stock awards to new and existing employees, which vest over three years, plus an additional 74,325 restricted stock awards to the members of the board of directors which vest on the one-year anniversary of the date of grant. During the year ended December 31, 2017, 142,218 restricted stock awards were forfeited by former employees. The weighted average fair value of the restricted shares granted during the year was $7.55, with a total grant date fair value of approximately $3.5 million after adjustment for estimated weighted average forfeiture rate of 4.8%.

During the year ended December 31, 2016, the Company issued 489,805 restricted stock awards to new and existing employees, which vest over three or four years, an additional 49,460 restricted stock awards to the members of the board of directors which vest on the one-year anniversary of the date of grant, plus an additional 40,876 immediately vested shares to employees and board members as a result of temporarily deferring 10% of 2015 employee salaries and director fees (the “Salary Replacement Program”). During the year ended December 31, 2016, 19,090 restricted stock awards were forfeited by former employees. The weighted average fair value of the restricted shares granted during the year was $10.99, with a total grant date fair value of approximately $6.4 million after adjustment for estimated weighted average forfeiture rate of 4.2%.

During the year ended December 31, 2015, the Company issued 249,917 restricted stock awards to new and existing employees, which vest over four years, plus an additional 27,204 restricted stock awards to the members of the board of directors which vest on the one-year anniversary of the date of grant. During the year ended December 31, 2015, 12,723 restricted stock awards were forfeited by former employees. The weighted average fair value of the restricted shares granted during the year was $21.83, with a total grant date fair value of approximately $6.1 million after adjustment for estimated weighted average forfeiture rate of 4.9%.

Restricted stock activity as of December 31, 2017, 2016 and 2015 and for the years then ended is presented in the table below (dollars in thousands, except per share data):

	2017			2016			2015		
	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value	Restricted Shares	Weighted Average Fair Value	Aggregate Intrinsic Value
Outstanding, beginning of the period	638,158	$ 14.22	$ 5,960	337,165	$ 28.16	$ 2,161	209,962	$ 43.86	$ 6,139
Granted	457,701	7.55	3,457	580,141	10.99	6,375	277,121	21.83	6,049
Vested	(222,568)	15.12	1,263	(260,058)	24.51	2,422	(137,195)	39.35	1,169
Canceled / Forfeited	(142,218)	10.23	814	(19,090)	22.03	202	(12,723)	32.97	154
Not vested, end of the period	731,073	10.55	1,667	638,158	14.22	5,960	337,165	28.16	2,161
Vested, end of the period	—	—	—	—	—	—	—	—	—
Expected to vest, end of the period	690,016	10.58	1,574	590,511	14.28	5,515	312,986	28.17	2,006

The Company recognized approximately $6.1 million, $6.5 million and $6.5 million in stock compensation expense during the years ended December 31, 2017, 2016 and 2015, respectively, for restricted shares granted to its officers, employees and directors. An additional $5.6 million of compensation expense will be recognized over the remaining vesting period.

Performance Stock Units

During the year ended December 31, 2017, the Company granted 30,000 Performance Stock Units (“PSUs”) to a new employee, at a weighted average fair value of $8.32 per unit and 160,908 PSUs to executive officers, as part of their overall compensation package, at a value of $13.91 per unit. All prices were determined using the Monte Carlo simulation model. During the year ended December 31, 2017, 99,363 PSUs were forfeited by former employees.

During the year ended December 31, 2016, the Company granted 285,800 PSUs to all employees as part of its LTIP, at a fair value of $16.32 per unit, and an additional 6,699 PSUs to new employees, at a fair value of $13.06 per unit using the Monte Carlo simulation model. During the year ended December 31, 2016, 1,300 PSUs were forfeited by former employees.

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.

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 became 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, 2017, 2016 and 2015. As of December 31, 2017, the Company had $31.8 million available under the share repurchase program for future purchases.

In October 2014, the Company amended its revolving credit facility with Royal Bank of Canada to, among other things, allow for share repurchases subject to certain conditions. The Company is currently in compliance with these conditions.

9. 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, 2017	December 31, 2016
Accounts receivable:		
Trade receivables	$ 6,565	$ 8,424
Receivable for Alta Resources distribution	1,993	1,993
Joint interest billings	4,030	3,519
Income taxes receivable	424	91
Other receivables	828	3,395
Allowance for doubtful accounts	(781)	(695)
Total accounts receivable	$ 13,059	$ 16,727
Prepaid expenses and other:		
Prepaid insurance	$ 1,177	$ 1,086
Other	715	701
Total prepaid expenses and other	$ 1,892	$ 1,787
Accounts payable and accrued liabilities:		
Royalties and revenue payable	$ 18,181	$ 16,920
Advances from partners	2,243	5,792
Accrued exploration and development	8,400	11,176
Accrued carried well costs	—	7,155
Trade payables	9,559	5,406
Accrued general and administrative expenses	2,960	5,016
Accrued operating expenses	1,654	1,867
Other accounts payable and accrued liabilities	3,758	1,803
Total accounts payable and accrued liabilities	$ 46,755	$ 55,135

Included in the table below is supplemental cash flow disclosures and non-cash investing activities during the years ended December 31, 2017, 2016 and 2015, in thousands:

	Year Ended December 31,		
	2017	**2016**	**2015**
Cash payments:			
Interest payments	$ 3,699	$ 3,806	$ 3,147
Income tax payments (refunds), net of cash refunds	616	(2,089)	(180)
Non-cash items excluded from investing activities in the consolidated statements of cash flows:			
Increase (decrease) in accrued capital expenditures	(9,931)	14,672	(22,879)

10. 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, 2017 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, 2017, the Company had invested approximately $46.9 million.

The following table presents condensed balance sheet data for Exaro as of December 31, 2017 and December 31, 2016. The balance sheet data was derived from the Exaro balance sheet as of December 31, 2017 and December 31, 2016 and was not adjusted to represent Contango's percentage of ownership interest in Exaro. Contango's share in the equity of Exaro at December 31, 2017 was approximately $18.4 million.

	December 31, 2017	December 31, 2016
	(in thousands)	
Current assets (1)	$ 17,063	$ 25,296
Non-current assets:		
Net property and equipment	82,450	90,621
Gas processing deposit	1,150	1,150
Other non-current assets	390	8
Total non-current assets	83,990	91,779
Total assets	$ 101,053	$ 117,075
Current liabilities (2)	$ 6,199	$ 65,694
Non-current liabilities:		
Long-term debt	40,375	—
Other non-current liabilities	3,858	8,106
Total non-current liabilities	44,233	8,106
Members' equity	50,621	43,275
Total liabilities & members' equity	$ 101,053	$ 117,075

(1) Approximately $12.8 million and $19.6 million of current assets as of December 31, 2017 and December 31, 2016, respectively, is cash.

(2) Approximately $59.3 million of current liabilities as of December 31, 2016, was attributable to Exaro's senior loan facility maturing in 2017, which has since been refinanced.

The following table presents the condensed results of operations for Exaro for the years ended December 31, 2017, 2016 and 2015. The results of operations for the years ended December 31, 2017, 2016 and 2015 were derived from Exaro's financial statements for the respective periods. The income statement data below was not adjusted to represent Contango's ownership interest but rather reflects the results of Exaro as a Company. The Company's share in Exaro's results of operations recognized for the years ended December 31, 2017, 2016 and 2015 was a gain of $2.7 million, net of no tax expense; a gain of $1.5 million, net of no tax expense; and a loss of $30.6 million, net of tax benefit of $16.5 million, respectively.

	Year Ended December 31,		
	2017	2016	2015
	($ in thousands)		
Production:			
Oil (MBbls)	101	127	166
Gas (MMcf)	9,019	10,626	13,059
Total (Mmcfe)	9,625	11,388	14,055
Oil and natural gas sales	$ 32,281	$ 30,028	$ 40,474
Other gain (loss)	5,368	(3,889)	6,358
Less:			
Lease operating expenses	15,479	15,846	20,922
Depreciation, depletion, amortization & accretion	9,857	10,644	29,417
Impairment expense	—	—	118,000
General & administrative expense	2,920	3,123	3,255
Income (loss) from continuing operations	9,393	(3,474)	(124,762)
Net other income (expense)	(2,189)	7,900	(2,910)
Net income (loss)	$ 7,204	$ 4,426	$ (127,672)

Included in Other gain (loss) are realized and unrealized gain (losses) attributable to derivatives, whose value is likely to change based on future oil and gas prices. Exaro's results of operations do not include income taxes, because Exaro is treated as a partnership for tax purposes.

11. 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 year ended December 31, 2017 and 2016 were as follows (in thousands):

	Year Ended December 31,	
	2017	2016
Balance as of the beginning of the period	$ 26,926	$ 27,109
Liabilities incurred during period	308	69
Liabilities settled during period	(4,503)	(707)
Accretion	1,056	1,187
Sales	(2,949)	(851)
Change in estimate	1,567	119
Balance as of the end of the period	$ 22,405	$ 26,926

All of the total liabilities incurred during the years ended December 31, 2017 and 2016 were related to new wells drilled during the period. All of the total liabilities settled during the years ended December 31, 2017 and 2016 were related to wells plugged and abandoned during the period.

12. Long-Term Debt

RBC Credit Facility

In October 2013, the Company entered into a $500 million revolving credit facility with Royal Bank of Canada and other lenders (the "RBC Credit Facility"), which matures on October 1, 2019. The borrowing base under the facility is redetermined each November 1 and May 1. Effective November 6, 2017, the borrowing base under the RBC Credit Facility was redetermined at $115 million.

Effective May 6, 2016, the RBC Credit Facility was amended to, among other things, extend the maturity of the facility from October 1, 2017 to October 1, 2019, increase the LIBOR, U.S. prime rate and federal funds rate margins to 2.5% - 4.0% and increase the commitment fee to 0.5%, regardless of the amount of the credit facility that is unused.

Initially, the Company incurred $2.2 million of arrangement and upfront fees in connection with the RBC Credit Facility which was to be amortized over the original four-year term of the facility. In May 2016, in connection with the amendment, the Company incurred an additional $1.0 million of arrangement and upfront fees. As of December 31, 2017, the remaining balance of these fees was $0.8 million, which will be amortized through October 1, 2019.

As of December 31, 2017, the Company had $85.4 million outstanding under the RBC Credit Facility, which matures on October 1, 2019, and $1.9 million in outstanding letters of credit. As of December 31, 2016, the Company had $54.4 million outstanding under the RBC Credit Facility and $1.9 million in outstanding letters of credit. As of December 31, 2017, borrowing availability under the RBC Credit Facility was $27.7 million.

The RBC Credit Facility is collateralized by a lien on substantially all the producing assets of the Company and its subsidiaries, including a security interest in the stock of Contango's subsidiaries and a lien on the Company's oil and gas properties.

Borrowings under the RBC Credit Facility bear interest at LIBOR, the U.S. prime rate, or the federal funds rate, plus a 2.5% to 4.0% margin, dependent upon the amount outstanding. Additionally, the Company must pay a 0.5% commitment fee regardless of the amount of the credit facility that is unused. Total interest expense under the RBC Credit Facility, including commitment fees, for the years ended December 31, 2017, 2016 and 2015 was approximately $4.1 million, $3.8 million and $3.2 million, respectively.

The RBC Credit Facility contains restrictive covenants which, among other things, restrict the declaration or payment of dividends by Contango and require 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 RBC Credit Facility Agreement. As of December 31, 2017, the Company was in compliance with all but the Current Ratio covenant under the RBC Credit Facility, although the Company obtained a waiver for such non-compliance. The RBC Credit Facility 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, payment defaults, breach of certain covenants, bankruptcy, insolvency or change of control events.

13. Commitments and Contingencies

Contango pays delay rentals on its leases and leases its office space and certain other equipment. The Company's corporate offices are located at 717 Texas Avenue in downtown Houston, Texas, under a lease that expires March 31, 2019.

As of December 31, 2017, minimum future lease payments for delay rentals and operating leases for Contango's fiscal years are as follows (in thousands):

Fiscal years ending December 31,	
2018	$ 3,542
2019	849
2020	112
2021	89
2022	82
2023 and thereafter	81
Total	$ 4,755

The amounts incurred under operating leases and delay rentals during the years ended December 31, 2017, 2016, and 2015 were approximately $4.8 million, $5.4 million and $6.3 million, respectively.

Throughput Contract Commitment

The Company 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. The Company currently forecasts that monthly gas volume deliveries through this line in its Southeast Texas area will not meet minimum throughput requirements under the agreement. Without further development in that area, the volume deficiency will continue through the expiration of the throughput commitment in March 2020. The throughput deficiency fee is paid in April of each calendar year. As of December 31, 2017, the Company estimates that the net deficiency fee will be approximately $1.0 million annually for the remaining contract period, based upon forecasted production volumes from existing proved producing reserves only, assuming no future development during this commitment period. As of December 31, 2017, based upon the current commodity price market and the Company's short term strategic drilling plans, the Company has recorded a $1.8 million loss contingency through December 31, 2018. The Company will continue to assess this commitment in light of its drilling and development plans for this area.

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.

In July 2010, several parties associated with a limited partnership, formed to invest in oil and gas properties, and that was dissolved in 1995, filed suit against a subsidiary of the Company and several co-defendants in district court for Madison County in Texas. The plaintiffs claim to own or have rights in certain oil and gas properties situated in Madison County, Texas by virtue of the partnership having interests in addition to those it held of record at the time of its dissolution, which were distributed to the partners in connection with such dissolution. A predecessor of the subsidiary of the Company involved in this case acquired a portion of the interests now claimed by the plaintiffs from a successor to the general partner of the aforementioned partnership in 2000. The case went to trial in December 2017. As the Court did not allow virtually all of the plaintiff's claims, a nominal settlement agreement was executed to settle all claims.

In November 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 decade-old poorly documented transactions. Based on prior summary judgments, the trial court has 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. In the fourth quarter of 2017 the Court of Appeals issued its opinion and affirmed the trial court's summary decision. The Company continues to vigorously defend this lawsuit and has filed a motion for rehearing with the Court of Appeals, and if denied, will petition the Texas Supreme Court.

In September 2012, a subsidiary of the Company was named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by the Company in the Catherine Henderson "A" Unit in Liberty County in Texas. This case was subsequently transferred to the district court for Liberty County, Texas and combined with a suit filed by other parties against the plaintiff claiming ownership of the disputed interest. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns an additional 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). The Company has made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder. The plaintiff previously alleged damages of approximately $10.7 million although the plaintiff's claim increases as additional hydrocarbons are produced from the subject wells. The trial court has entered judgment in favor of the Company's subsidiary and the successors to the grantors under the aforementioned deeds. The plaintiff appealed the trial court's decision to the applicable state Court of Appeals. On December 14, 2017, the Court of Appeals affirmed the judgement in the Company's favor. The plaintiff has filed a motion for rehearing. The Company continues to vigorously defend this lawsuit and believes that it has meritorious defenses. The Company believes if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights the Company may have against other working interest and/or royalty interest owners in the unit.

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 were terminated, 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 provide 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 will automatically renew for additional one year terms, unless Contango or the executive provides prior notice of intention not to extend the agreement.

Under the Employment Agreements, Mr. Keel is entitled to a base salary of $600,000, Mr. Grady is entitled to a base salary of $400,000, Mr. Mengle is entitled to a base salary of $300,000 and Mr. Atkins is entitled to a base salary of $310,000. The Employment Agreements provide 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.

14. 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, 2017, 2016 and 2015 is presented below (in thousands):

	Year Ended December 31, 2017		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (17,643)	24,686	$ (0.71)
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	$ (17,643)	24,686	$ (0.71)

	Year Ended December 31, 2016		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (58,029)	21,424	$ (2.71)
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	$ (58,029)	21,424	$ (2.71)

	Year Ended December 31, 2015		
	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$ (335,048)	18,965	$ (17.67)
Diluted Earnings per Share:			
Effect of potential dilutive securities:			
Weighted average of incremental shares (stock options and restricted stock)	—	—	—
Net loss attributable to common stock	$ (335,048)	18,965	$ (17.67)

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 1,282,590 shares for the year ended December 31, 2017, 1,282,957 shares for the year ended December 31, 2016 and 453,626 shares for the year ended December 31, 2015.

15. Income Taxes

The Tax Cuts and Jobs Act 2017

On December 22, 2017, the United States enacted tax reform legislation known as the H.R.1, commonly referred to as the "Tax Cuts and Jobs Act" (the "Act"), resulting in significant modifications to existing law. The Company has completed the accounting for the effects of the Act during 2017. Our financial statements for the year ended December 31, 2017 reflect certain effects of the Act which includes a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018, as well as other changes. Due to the Company's valuation allowance position and as a result of changes to tax laws and rates under the Act, the Company recorded a net tax benefit due primarily to the remeasurement of deferred tax assets and liabilities from 35% to 21% and the removal of the valuation allowance on the estimated refundable Alternative Minimum Tax ("AMT") credits. The valuation allowance decreased by $35.7 million in 2017 due to the changes to tax laws and rates under the Act and increased by $7.2 million for normal operations.

The staff of the US Securities and Exchange Commission has recognized the complexity of reflecting the impacts of the Act, and on December 22, 2017 issued guidance in Staff Accounting Bulletin 118 ("SAB 118") which clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one year period to complete the required analyses and accounting (the measurement period). SAB 118 describes three scenarios associated with a company's status of accounting for income tax reform: (1) a company is complete with its accounting for certain effects of tax reform, (2) a company is able to determine a reasonable estimate for certain effects of tax reform and records that estimate as a provisional amount, or (3) a company is not able to determine a reasonable estimate and therefore continues to apply ASC 740, based on the provisions of the tax laws that were in effect immediately prior to the Act being enacted. The Company has completed the accounting for the effects of the Act.

Actual income tax expense differs from income tax expense computed by applying the U.S. federal statutory corporate rate of 35 percent to pretax income as follows (dollars in thousands):

	Year Ended December 31,					
	2017		2016		2015	
Provision/(benefit) at statutory tax rate	$ (6,314)	35.00 %	$ (20,190)	35.00 %	$ (148,925)	35.00 %
State income tax provision, net of federal benefit	(864)	4.79 %	(774)	1.34 %	(116)	0.03 %
Permanent differences	50	(0.28)%	67	(0.12)%	30	(0.01)%
Stock based compensation	(361)	2.00 %	1,599	(2.77)%	—	— %
Valuation allowance	7,209	(39.96)%	20,026	(34.72)%	55,310	(13.00)%
Rate change (35% to 21% fed rate)	35,250	(195.41)%	—	— %	—	— %
Valuation allowance for remeasurement and changes relating to the Tax Cuts and Jobs Act	(35,674)	197.76 %	—	— %	—	— %
Other	309	(1.71)%	(386)	0.68 %	2,008	(0.47)%
Income tax provision /(benefit)	$ (395)	2.19 %	$ 342	(0.59)%	$ (91,693)	21.55 %

The effective tax rate for the years ended December 31, 2017, 2016 and 2015 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,		
	2017	2016	2015
Current tax provision (benefit):			
Federal	$ (424)	$ (91)	$ —
State	453	433	636
Total	$ 29	$ 342	$ 636
Deferred tax provision (benefit):			
Federal	$ (424)	$ —	$ (92,329)
State	—	—	—
Total	$ (424)	$ —	$ (92,329)
Total tax provision (benefit):			
Federal	$ (848)	$ (91)	$ (92,329)
State	453	433	636
Total	$ (395)	$ 342	$ (91,693)
Included in gain (loss) from investment in affiliates	$ —	$ —	$ (16,467)
Total income tax provision (benefit)	$ (395)	$ 342	$ (75,226)

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

	December 31, 2017	December 31, 2016
Deferred tax assets:		
Net operating loss carryforward	$ 60,464	$ 69,828
Income tax credits	454	908
Derivative instruments	261	1,208
Deferred compensation	1,418	308
Oil and gas properties	—	6,806
Other	491	1,477
Total deferred tax assets before valuation allowance	$ 63,088	$ 80,535
Valuation allowance	(49,032)	(77,497)
Net deferred tax assets	$ 14,056	$ 3,038
Deferred tax liability:		
Oil and gas properties	$ (10,567)	$ —
Investment in affiliates	(3,065)	(3,038)
Other	—	—
Deferred tax liability	$ (13,632)	$ (3,038)
Total net deferred tax	$ 424	$ —

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 of $49.0 million.

As of December 31, 2017, the Company had federal net operating loss (“NOL”) carryforwards of approximately $284.4 million and state NOLs of $20.4 million. The federal NOL carryforwards reported as of December 31, 2014 were acquired in the 2013 Merger with Crimson. A valuation allowance was recorded at the time of the Merger to reflect the impact of Internal Revenue Code Section 382 limitations on the use of the federal NOLs acquired. The federal NOL carryforwards expire at various dates beginning in 2018 and ending in 2037.

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, 2016	$ 360
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	—
Change in rate due to remeasurement	(133)
Balance at December 31, 2017	$ 227

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, 2017 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 statute of limitations prior to December 31, 2017.

Generally, the Company's income tax years of 1998 through 2016 remain open and subject to examination by Federal tax authorities, and the tax years of 2010 through 2016 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.

16. Related Party Transactions

Olympic Energy Partners

Mr. Joseph J. Romano was elected President and Chief Executive Officer of the Company in December 2012 and named Chairman of the Company in April 2013. Upon the Merger with Crimson on October 1, 2013, Mr. Romano resigned as President and Chief Executive Officer, but continued as Chairman. Mr. Romano is also the President and Chief Executive Officer of Olympic Energy Partners LLC ("Olympic"). Olympic has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant's working interest ("WI"), net revenue interest ("NRI") and describe when such interests are earned.

Olympic last participated with the Company in the drilling of wells in March 2010, and its ownership in Company-operated wells is limited to its Dutch and Mary Rose wells as follows:

	Olympic	
	WI	***NRI***
Dutch #1 - #5	3.53%	2.84%
Mary Rose #1	3.61%	2.70%
Mary Rose #2 - #3	3.61%	2.58%
Mary Rose #4	2.34%	1.70%
Mary Rose #5	2.56%	1.87%

During each of the years ended December 31, 2017 and 2016, Mr. Romano earned $56 thousand for his service as a director of the Company. Additionally, during the year ended December 31, 2017, Mr. Romano received 14,865 shares of restricted stock, which vest 100% on the one-year anniversary of the date of grant, as part of his board of director compensation. During the year ended December 31, 2016, Mr. Romano received 261 shares of restricted stock, pursuant to the Salary Replacement Program, and an additional 9,892 shares of restricted stock, which vest in one year, as part of Mr. Romano's board of director compensation. The Company recognized compensation expense of $117 thousand and $99 thousand related to shares granted to Mr. Romano during the years ended December 31, 2017 and 2016, respectively.

Below is a summary of payments the Company received from (paid to) Olympic in the ordinary course of business in its capacity as operator of the wells and platforms for the periods indicated. The Company made and received similar types of payments with other well owners (in thousands):

	Year Ended December 31,		
	2017	**2016**	**2015**
Revenue payments as well owners	$ (2,673)	$ (2,485)	$ (4,115)
Joint interest billing receipts	391	323	531

As of December 31, 2017 and 2016, the Company's consolidated balance sheets reflected the following balances relating to Olympic (in thousands):

	Year Ended December 31, 2017	2016
Accounts Receivable: Joint interest billing	$ 48	$ 59
Accounts Payable: Royalties and revenue payable	(442)	(557)

Oaktree Capital Management L.P.

In November 2017, Oaktree Capital Management L.P. ("Oaktree") sold all of its shares of the Company's stock. Mr. James Ford, previously a Managing Director and Portfolio Manager within Oaktree, and a Senior Advisor to Oaktree at the time of sale, has been on the Company's board of directors since October 1, 2013. Mr. Ford was previously a member of Crimson's board of directors from February 2005 until the closing of the Merger.

Historically, all cash and equity awards payable to Mr. Ford were instead granted to an affiliate of Oaktree. Beginning October 1, 2016, all cash and equity awards payable to Oaktree for Mr. Ford's service as a director became payable to him directly. During the year ended December 31, 2017, Mr. Ford directly earned $68 thousand for his service. During the year ended December 31, 2016, Mr. Ford directly earned $18 thousand for his service, and the affiliate of Oaktree earned $48 thousand, as a result of Mr. Ford's participation. During the year ended December 31, 2017, Mr. Ford received 14,865 shares of restricted stock, which vest 100% on the one-year anniversary of the date of grant, as part of his board of director compensation. During the year ended December 31, 2016, the affiliate of Oaktree received 313 shares of restricted stock, pursuant to the Salary Replacement Program, and an additional 9,892 shares of restricted stock, which also vest in one year, as part of Mr. Ford's board of director compensation. During the years ended December 31, 2017 and 2016, the Company recognized compensation expense of $117 thousand and $99 thousand, respectively, related to the shares granted to an affiliate of Oaktree and Mr. Ford.

17. Subsequent Events

The Company has evaluated subsequent events through the date the financial statements were available to be issued. Nothing that would require recognition or disclosure in the financial statements was identified in addition to the items disclosed in the financial statements.

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,	
	2017	2016
Proved oil and gas properties	$ 1,239,662	$ 1,188,065
Unproved oil and gas properties	35,243	38,338
	1,274,905	1,226,403
Less accumulated depreciation, depletion, amortization and impairment	(929,210)	(886,303)
Net capitalized costs	$ 345,695	$ 340,100

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,		
	2017	2016	2015
Property acquisition costs:			
Unproved	$ 6,540	$ 29,767	$ 11,453
Proved	—	—	—
Exploration costs	8,158	9,126	29,477
Development costs	45,016	1,890	20,120
Total costs incurred	$ 59,714	$ 40,783	$ 61,050

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,		
	2017	2016	2015
Property acquisition costs	$ —	$ —	$ —
Exploration costs	—	—	—
Development costs	429	395	4,503
Total costs incurred	$ 429	$ 395	$ 4,503

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, 2017, 2016, 2015 and 2014, 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, 2017, 2016, 2015 and 2014, 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, 2014	8,415	7,509	179,651	275,193
Sale of minerals in place	—	—	—	—
Extensions and discoveries	460	81	543	3,788
Revisions of previous estimates	(3,160)	(1,229)	(31,451)	(57,782)
Production	(924)	(967)	(22,615)	(33,961)
December 31, 2015	4,791	5,394	126,128	187,238
Sale of minerals in place	(250)	(101)	(2,045)	(4,151)
Extensions and discoveries	63	—	—	375
Revisions of previous estimates	(583)	(218)	(927)	(5,730)
Production	(597)	(716)	(18,103)	(25,982)
December 31, 2016	3,424	4,359	105,053	151,750
Sale of minerals in place	—	—	(893)	(893)
Extensions and discoveries	7,159	1,989	8,191	63,076
Revisions of previous estimates	584	(224)	(6,722)	(4,556)
Production	(518)	(517)	(13,910)	(20,123)
December 31, 2017	10,649	5,607	91,719	189,254
Proved Developed Reserves as of:				
December 31, 2014	4,114	5,637	150,235	208,734
December 31, 2015	2,869	4,354	113,952	157,288
December 31, 2016	2,158	3,509	95,396	129,399
December 31, 2017	3,364	3,596	82,133	123,895
Proved Undeveloped Reserves as of:				
December 31, 2014	4,301	1,872	29,416	66,459
December 31, 2015	1,922	1,040	12,176	29,950
December 31, 2016	1,266	850	9,657	22,351
December 31, 2017	7,285	2,011	9,586	65,359

During the year ended December 31, 2017, our proved reserves increased by approximately 37.5 Bcfe attributable primarily to new additions and extensions related to our drilling program in West Texas and positive revision of reserve estimates due to higher commodity prices, partially offset by 2017 production and a reduction in proved undeveloped reserves required by SEC guidelines for those reserves that are not likely to be drilled within a five year period after those reserves are initially recorded.

During the year ended December 31, 2016, our proved reserves decreased by approximately 35.5 Bcfe attributable primarily to the impact of the dramatic decline in commodity prices on the value and volume of our proved reserves, and in part to the impact of the significant reduction in our capital spending in response to the low and uncertain commodity price environment.

During the year ended December 31, 2015, our proved reserves decreased by approximately 88.0 Bcfe attributable primarily to the impact of the dramatic decline in commodity prices on the value and volume of our proved reserves, and in part to the impact of the significant reduction in our capital spending in response to the low and uncertain commodity price environment.

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, 2017, 2016, 2015 and 2014, attributable to its Investment in Exaro.

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Proved Developed and Undeveloped Reserves as of:			
December 31, 2014	791	65,412	70,158
Sale of minerals in place	—	—	—
Extensions and discoveries	1	120	128
Revisions of previous estimates	(289)	(24,637)	(26,373)
Production	(61)	(4,821)	(5,189)
December 31, 2015	442	36,074	38,724
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Revisions of previous estimates	(35)	(1,710)	(1,919)
Production	(47)	(3,923)	(4,205)
December 31, 2016	360	30,441	32,600
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Revisions of previous estimates	6	1,635	1,672
Production	(37)	(3,330)	(3,553)
December 31, 2017	329	28,746	30,719
Proved Developed Reserves as of:			
December 31, 2014	529	45,127	48,301
December 31, 2015	442	36,074	38,724
December 31, 2016	360	30,441	32,600
December 31, 2017	325	28,443	30,390
Proved Undeveloped Reserves as of:			
December 31, 2014	262	20,285	21,857
December 31, 2015	—	—	—
December 31, 2016	—	—	—
December 31, 2017	4	303	329

During the year ended December 31, 2017, the decrease in Exaro's proved reserves attributable to our Investment in Exaro was approximately 1.9 Bcfe.

During the year ended December 31, 2016, the decrease in Exaro's proved reserves attributable to our Investment in Exaro was approximately 6.1 Bcfe. This decrease was primarily attributable to the impact of the significant reduction in capital spending in response to the low and uncertain commodity price environment.

During the year ended December 31, 2015, the decrease in Exaro's proved reserves attributable to our Investment in Exaro was approximately 31.4 Bcfe. This decrease was attributable to the impact of the dramatic decline in commodity prices on the value and volume of proved reserves and the impact of the significant reduction in capital spending in response to the low and uncertain commodity price environment.

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, 2017, 2016 and 2015 are shown below (in thousands):

	As of December 31,		
	2017	2016	2015
Future cash inflows	$ 877,721	$ 447,417	$ 623,014
Future production costs	(243,415)	(154,249)	(200,953)
Future development costs	(138,840)	(51,573)	(69,147)
Future income tax expenses	(3,226)	—	—
Future net cash flows	492,240	241,595	352,914
10% annual discount for estimated timing of cash flows	(236,333)	(75,367)	(103,508)
Standardized measure of discounted future net cash flows	$ 255,907	$ 166,228	$ 249,406

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, 2017, future cash inflows were based on unadjusted prices of $2.98 per MMbtu of natural gas, $49.92 per barrel of oil, and $18.59 per barrel of NGLs. As of December 31, 2016, future cash inflows were based on unadjusted prices of $2.49 per MMbtu of natural gas, $39.72 per barrel of oil, and $13.62 per barrel of NGLs. As of December 31, 2015, future cash inflows were based on unadjusted prices of $2.59 per MMbtu of natural gas, $47.36 per barrel of oil, and $14.41 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, 2017, 2016 and 2015 attributable to its Investment in Exaro are shown below (in thousands):

	As of December 31,		
	2017	2016	2015
Future cash inflows	$ 102,813	$ 88,398	$ 117,211
Future production costs	(60,541)	(55,610)	(65,042)
Future development costs	(2,699)	(2,380)	(2,399)
Future income tax expenses [(1)]	—	—	—
Future net cash flows	39,573	30,408	49,770
10% annual discount for estimated timing of cash flows	(15,207)	(10,630)	(18,472)
Standardized measure of discounted future net cash flows	$ 24,366	$ 19,778	$ 31,298

(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, 2017 production were $2.97 per MCF of gas, $48.90 per barrel of oil, and $22.97 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging gains of $1.1 million for the year ended December 31, 2017.

The average realized prices for the year ended December 31, 2016 production were $2.42 per MCF of gas, $38.52 per barrel of oil, and $15.79 per barrel of NGL. Sales are based on market prices and do not include the effects of realized derivative hedging gains of $1.8 million for the year ended December 31, 2016.

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,		
	2017	2016	2015
Changes in standardized measure due to current year operation:			
Sales of natural gas and oil produced during the period, net of production expenses	$ (51,359)	$ (49,046)	$ (78,651)
Extensions and discoveries	69,179	911	8,584
Net change in prices and production costs	57,026	(44,033)	(420,890)
Changes in estimated future development costs	—	10,751	23,771
Revisions in quantity estimates	4,546	(8,236)	(156,249)
Purchase of reserves	—	—	—
Sale of reserves	(235)	(2,509)	—
Accretion of discount	16,623	24,940	79,687
Changes in income taxes	(1,376)	—	148,854
Change in the timing of production rates and other	(4,725)	(15,956)	(3,716)
Net change	89,679	(83,178)	(398,610)
Beginning of year	166,228	249,406	648,016
End of year	$ 255,907	$ 166,228	$ 249,406

During the year ended December 31, 2017, our proved reserves increased by approximately 37.5 Bcfe and our standardized measure increased by approximately $89.7 million. This increase is primarily attributable to the extensions and additions related to our assets in West Texas and positive revisions of reserve estimates due to higher commodity prices, partially offset by decreases attributable to production and decreases due to the expiration of undeveloped reserves.

During the year ended December 31, 2016, our proved reserves decreased by approximately 35.5Bcfe and our standardized measure decreased by approximately $83.2 million. This decrease is attributable primarily to the impact of the dramatic decline in commodity prices on the value and volume of our proved reserves, and in part to the impact of the significant reduction in our capital spending in response to the low and uncertain commodity price environment.

During the year ended December 31, 2015, our proved reserves decreased by approximately 88.0 Bcfe and our standardized measure decreased by approximately $398.6 million. This decrease is attributable primarily to the impact of the dramatic decline in commodity prices on the value and volume of our proved reserves, and in part to the impact of the significant reduction in our capital spending in response to the low and uncertain commodity price environment.

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

	Year Ended December 31,		
	2017	2016	2015
Changes in standardized measure due to current year operation:			
Sales of natural gas and oil produced during the period, net of production expenses	$ (6,744)	$ (5,531)	$ (8,745)
Extensions and discoveries	—	—	161
Net change in prices and production costs	9,951	(7,160)	(49,933)
Changes in estimated future development costs	5	—	3,958
Revisions in quantity estimates	1,236	(1,616)	(22,973)
Purchase of reserves	—	—	—
Sale of reserves	—	—	—
Accretion of discount	1,978	3,130	10,061
Changes in income taxes	—	—	—
Change in the timing of production rates and other	(1,838)	(343)	(1,838)
Net change	4,588	(11,520)	(69,309)
Beginning of year	19,778	31,298	100,607
End of year	$ 24,366	$ 19,778	$ 31,298

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, 2017 and 2016, (in thousands, except per share amounts):

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
Year ended December 31, 2017:				
Revenues	$ 19,424	$ 20,276	$ 18,830	$ 20,015
Operating Loss [1]	$ (5,897)	$ (6,285)	$ (6,022)	$ (5,311)
Net loss attributable to common stock [2]	$ 885	$ (6,034)	$ (6,916)	$ (5,578)
Net income (loss) per share [3]:				
Basic:	$ 0.04	$ (0.24)	$ (0.28)	$ (0.23)
Diluted:	$ 0.04	$ (0.24)	$ (0.28)	$ (0.23)
Year ended December 31, 2016:				
Revenues	$ 17,582	$ 19,362	$ 19,576	$ 21,663
Operating Loss [1]	$(14,640)	$(12,493)	$ (12,843)	$ (13,465)
Net loss attributable to common stock [2]	(11,404)	(17,296)	(12,485)	(16,844)
Net loss per share [3]:				
Basic:	$ (0.60)	$ (0.90)	$ (0.55)	$ (0.69)
Diluted:	$ (0.60)	$ (0.90)	$ (0.55)	$ (0.69)

(1) Represents natural gas and oil 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 and oil 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.

FOURTH AMENDMENT AND WAIVER TO CREDIT AGREEMENT

This FOURTH AMENDMENT AND WAIVER TO CREDIT AGREEMENT ("Amendment"), dated as of March 7, 2018, is by and among Contango Oil & Gas Company, a Delaware corporation (the "Borrower"), the lenders party to the Credit Agreement described below (the "Lenders"), Royal Bank of Canada, as administrative agent for the Lenders (in such capacity, the "Administrative Agent"), and the other parties in the capacities therein identified.

RECITALS

WHEREAS, the Borrower, the Lenders, the Administrative Agent and certain other Persons are parties to the Credit Agreement, dated as of October 1, 2013, as amended by the First Amendment to Credit Agreement dated as of April 11, 2014, the Second Amendment to Credit Agreement dated as of October 28, 2014 and the Third Amendment to Credit Agreement dated as of May 6, 2016 (as amended, supplemented, amended and restated or otherwise modified from time to time, the "Credit Agreement"); and

WHEREAS, the Borrower, the Administrative Agent and the Lenders intend to amend and waive certain provisions of the Credit Agreement in certain respects as set forth herein.

NOW, THEREFORE, in consideration of the premises and the mutual covenants, representations and warranties contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

AGREEMENT

Section 1. Definitions. Capitalized terms used herein but not defined herein shall have the meanings as given them in the Credit Agreement, unless the context otherwise requires.

Section 2. Amendments Sections 8.06, 8.07 and 8.08 of the Credit Agreement. Sections 8.06 and 8.08 of the Credit Agreement are hereby amended by deleting the percentage "90%" or "80%" (as applicable) appearing therein and replacing it with the percentage "95%" everywhere such 90% or 80% appears in such Sections.

Section 3. Waiver. The Majority Lenders hereby waive the requirement in Section 9.12 of the Credit Agreement that the Borrower not permit its ratio of Current Assets to Current Liabilities to be less than 1.00 to 1.00 for the fiscal quarter ending December 31, 2017. The foregoing waiver is not a waiver of any other provision of the Credit Agreement and is not a waiver of Section 9.12 of the Credit Agreement in respect of any fiscal quarter other than for the fiscal quarter ending December 31, 2017.

Section 4. Conditions to Effectiveness. The Effective Date of this Amendment shall be deemed to occur on the date (the "Effective Date") when the Administrative

Agent has received counterparts of this Amendment duly executed by the Borrower, the Administrative Agent, the Issuing Bank, the Swing Line Lender and the Majority Lenders and upon the prior or concurrent satisfaction of each of the following conditions:

(a) the Administrative Agent shall have received, for the account of each Lender that is a signatory hereto, from the Borrower all agreed upon fees in connection with this Amendment;

(b) the Administrative Agent shall have received a certificate dated as of the date hereof, duly executed by an officer of the Borrower, certifying the representations and warranties set forth in Section 6 hereof are true and correct.

Notwithstanding the foregoing, this Amendment shall not become effective unless each of the foregoing conditions is satisfied (or waived in writing) on or prior to February 28, 2018.

Section 5. Post-Closing Condition. Within forty-five (45) days following the Effective Date (or such later date as the Administrative Agent shall agree to in its sole discretion), the Borrower shall have delivered, or cause to be delivered, to the Administrative Agent executed new Mortgages or supplements to existing Mortgages (x) sufficient to cause the Borrower to be in compliance with Section 8.08 of the Credit Agreement, as amended hereby (as determined by the Administrative Agent in its sole discretion) and (y) in form and substance substantially similar to the existing applicable Loan Documents.

Section 6. Representations and Warranties. The Borrower hereby represents and warrants that after giving effect hereto:

(a) the representations and warranties of the Borrower and its Subsidiaries contained in the Loan Documents are true and correct in all material respects (except to the extent such representations and warranties are qualified by a materiality qualifier, which shall be true and correct in all respects), other than those representations and warranties that expressly relate solely to a specific earlier date, which shall remain correct in all material respects (except to the extent such representations and warranties are qualified by a materiality qualifier, which shall be true and correct in all respects) as of such earlier date; and

(b) after giving effect to the waiver contained in this Amendment no Default, Event of Default or Deficiency has occurred and is continuing.

Section 7. Loan Document; Ratification.

(a) This Amendment is a Loan Document. Each reference to the Credit Agreement in any Loan Document will deemed to be a reference to the Credit Agreement as amended by this Amendment.

(b) Except as amended hereby, the Credit Agreement remains in full force and effect and the Borrower hereby ratifies, approves and confirms in every respect all the terms, provisions, conditions and obligations of the Credit Agreement as amended hereby.

Section 8. GOVERNING LAW. THIS AMENDMENT AND ANY CLAIMS, CONTROVERSY, DISPUTE OR CAUSE OF ACTION (WHETHER IN CONTRACT OR TORT OR OTHERWISE) BASED UPON, ARISING OUT OF OR RELATING TO THIS AMENDMENT AND THE TRANSACTIONS CONTEMPLATED HEREBY SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

Section 9. Severability. In the event that any one or more of the provisions contained in this Amendment shall, for any reason, be held invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not effect any other provision of this Amendment.

Section 10. Counterparts. This Amendment may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument, and any party hereto may execute this Amendment by signing one or more counterparts. Any signature hereto delivered by a party by facsimile or electronic transmission shall be deemed to be an original signature hereto.

Section 11. Successors and Assigns. This Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns.

Section 12. Entire Agreement. THIS AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT OF THE PARTIES WITH RESPECT TO THE SUBJECT MATTER HEREOF AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES.

THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

(*Signature Pages Follow*)

In Witness Whereof, the parties hereto have caused this Amendment to be duly executed and delivered by their respective duly authorized officers as of the date first written above.

BORROWER:

CONTANGO OIL & GAS COMPANY

By: /s/ SERGIO CASTRO
Name: Sergio Castro
Title: Vice President and Treasurer

ADMINISTRATIVE AGENT:

ROYAL BANK OF CANADA

By: /s/ RODICA DUTKA
Name: Rodica Dutka
Title: Authorized Signatory

ISSUING BANK:

ROYAL BANK OF CANADA,

By: /s/ EMILEE SCOTT
Name: Emilee Scott
Title: Authorized Signatory

LENDER:

ROYAL BANK OF CANADA,

By: /s/ JAY SARTAIN
Name: Jay Sartain
Title: Authorized Signatory

LENDER:

REGIONS BANK

By: /s/ DANIEL G. STEELE
Name: Daniel G. Steele
Title: Managing Director

LENDER:

CAPITAL ONE, NATIONAL ASSOCIATION

By: /s/ SCOTT MACKEY
Name: Scott Mackey
Title: Director

LENDER:

COMPASS BANK

By: /s/ GABRIELA AZCARATE
Name: Gabriela Azcarate
Title: Vice President

LENDER:

BARCLAYS BANK PLC

By: / s/ SYDNEY G. DENNIS
Name: Sydney G. Dennis
Title: Director

LENDER:

BOKF, NA DBA BANK OF TEXAS

By: / s/ BRANDON STARR
Name: Brandon Starr
Title: Vice President

LENDER:

CADENCE BANK

By: / s/ ANTHONY BLACO
Name: Anthony Blanco
Title: Senior Vice President

LENDER:

CITIBANK, N.A.

By: / s/ JEFF ARD
Name: Jeff Ard
Title: Vice President

LENDER:

IBERIABANK

By: / s/ BLAKELY NORRIS
Name: Blakely Norris
Title: Vice President

Exhibit 21.1

CONTANGO OIL AND GAS COMPANY
LIST OF WHOLLY-OWNED SUBSIDIARIES
DECEMBER 31, 2017

Wholly-Owned Subsidiaries of Contango Oil & Gas Company as of 12/31/17

Crimson Exploration Inc.
Crimson Exploration Operating, Inc.
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, 2017

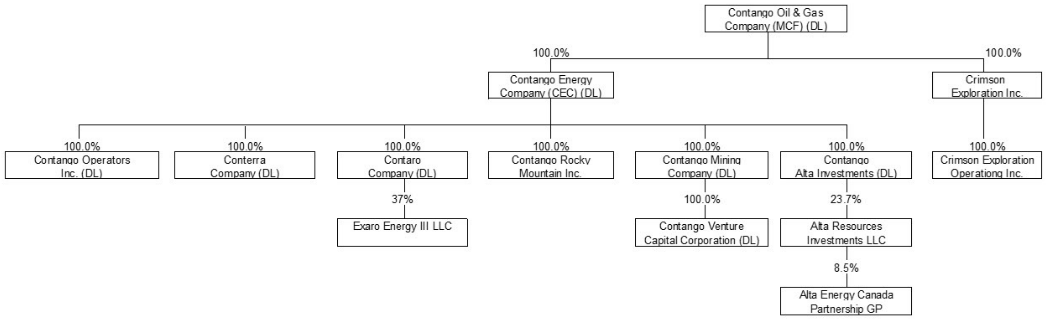


Exhibit 23.1

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 9, 2018

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, 2017.

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The firm of Netherland, Sewell & 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 Oil & Gas Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

Netherland, Sewell & 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.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons

Danny D. Simmons, P.E.
President and Chief Executive Officer

Houston, Texas
March 9, 2018

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 9, 2018

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, 2017.

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.

W.D. Von Gonten Jr.

Name: W.D. Von Gonten JR
Title: President

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 9, 2018, 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, 2017. 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. 333-193613) and on Forms S-8 (File No. 333-189302 and File No. 333-170236).

/s/ GRANT THORNTON LLP

Houston, Texas

March 9, 2018

Exhibit 31.1

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, Allan D. Keel, 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 9, 2018 By: /s/ ALLAN D. KEEL

Allan D. Keel
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 9, 2018

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, 2017 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Allan D. Keel, 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 9, 2018

By: /s/ ALLAN D. KEEL

Allan D. Keel
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, 2017 (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 9, 2018

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

January 23, 2018

Mr. Steve Mengle
Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, TX 77002

Dear Mr. Mengle:

In accordance with your request, William M. Cobb & Associates, Inc. (Cobb & Associates) has estimated the proved reserves and future income as of January 1, 2018, attributable to the interest of Contango Oil & Gas Company and its subsidiaries (Contango) in certain oil and gas properties located in state and federal waters of the Gulf of Mexico, and onshore in Mississippi and Texas. This report was completed on January 23, 2018.

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. Values shown are determined utilizing constant oil and gas prices and well operating expenses. The discounted present worth of future income values shown in Table 1 are not intended to necessarily 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.

TABLE 1

CONTANGO - NET RESERVES AND VALUE
AS OF JANUARY 1, 2018
CONSTANT SEC OIL AND GAS PRICES

				Future Net Pre-Tax Income – M$	
Reserve Category	**Net Gas (MMCF)**	**Net NGL (MBBL)**	**Net Oil (MBBL)**	**Undiscounted**	**Discounted at 10%**
Proved					
Producing	62,998	2,271	1,583	219,343	148,086
Undeveloped	6,497	1,583	4,796	147,277	32,135
Total Proved	69,495	3,854	6,379	366,620	180,221

Total proved reserves as of January 1, 2018 are 130,893 MMCFE. This amount is calculated using a six MCF per barrel ratio applied to condensate and NGL volumes.

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.

Our 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 ended December 31, 2017 (the "Form 10-K"), covers
130,893 MMCFE, or 70.2 percent of the total company present value discounted at ten percent (PV10) presented in Contango's Form 10-K. We have used all assumptions, data, methods, and procedures considered necessary and appropriate to prepare this report.

DISCUSSION

Eugene Island 10

Eugene Island 10 is located in federal and 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.

Contango's Louisiana State leases in this field 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, produce from the main CibOp sand. The Mary Rose 5 well produces from a separate, and much smaller, CibOp reservoir.

All wells now produce to the Contango 'H' platform located in Eugene Island Block 11. The Dutch 1, 2, and 3 wells previously produced to the Chevron EI-24 platform but were switched to the Contango 'H' platform in 2013.

Proved reserves for the Eugene Island 10 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. Contango plans to install a second stage of compression in the third quarter of 2018, which will lower the compressor inlet pressure to 200 psig or lower. Forecasts for the producing wells are modeled to increase at the time the second stage is expected online. There are no remaining capital or startup costs for compression on the 'H' platform. The custody transfer meter is downstream of the compressor and other supply and fuel gas, so engineered and forecasted volumes already have these compressor and other fuel volumes removed, at an estimated total of 1,493 MCFD.

Contango's working interest ownership is approximately 55 percent in the Dutch wells and 53 percent in the Mary Rose 1 through 3 wells. The Contango working interest in the Mary Rose 4 and 5 wells is approximately 35 and 38 percent, respectively. Based on future net income, discounted at ten percent

(PV10), approximately 69.1 percent of the evaluated Contango proved reserve value is attributable to the Eugene Island 10 wells.

Two wells on the State acreage originally produced from gas reservoirs separate from the main CibOp reservoir. The Eloise 3 well produced and depleted a lower RobL sand and was recompleted to an isolated CibOp sand during the last quarter of 2011. This stray CibOp producer, now called the Mary Rose 5, began producing in January 2012. The Eloise 5 well has also produced and depleted a lower RobL sand and was recompleted to the main CibOp reservoir mid-year 2011. The Eloise 5 was renamed the Dutch 5 well and began producing from the main CibOp reservoir in July 2011.

Ship Shoal 263

Contango drilled the Ship Shoal 263 B-1 well in 2009 and completed the well for production in a gas sand at 15,850 feet. The well began producing on June 30, 2010 and has produced approximately 8.5 BCF of gas and 561 MBBL of condensate to date. This well has been plugged and abandoned and will be dropped from future reports.

Vermilion 170

Contango drilled the OCS-G-33596 #1 in March of 2011 and successfully completed the well in the Big A sand at a depth of approximately 13,800 feet. Production started in September 2011 upon installation of a production platform in 87 feet of water. Current production rates are 5.0 MMCF per day with 38 barrels of condensate. Cumulative production to date is approximately 22.6 BCF of gas and 453 MBBL of condensate. Proved producing reserves are based on analysis of the gas rate versus time production history for the well.

South Timbalier 17-1

In mid to late-2013, Contango drilled and tested a well on its South Timbalier 17 lease. The South Timbalier 17-1 was drilled to a total measured depth of 11,432 feet, and was completed in a sand from 11,174 - 11,200 feet. The well tested in September of 2013 at a rate of 12.7 MMCF per day. Facilities were installed in 2014 and the well commenced production in July of 2014, with peak daily rates of 15.0 MMCF per day with 166 BBL of condensate. The well has been plugged and abandoned, having produced 3.2 BCF of gas and 20 MBBL of condensate.

Tuscaloosa Marine Shale Wells

Contango owns a working interest in four Tuscaloosa Marine Shale (TMS) wells drilled from 2012 to 2014, which are operated by Goodrich Petroleum. The wells are located in Wilkinson and Amite Counties, Mississippi, and they produce from the Cretaceous aged TMS at a true vertical depth of approximately 12,000 feet. The wells were drilled horizontally with variable lateral lengths that average approximately 6,000’. The wells were hydraulically fracture stimulated to increase well deliverability. Peak oil rates for the wells ranged from 225 to 875 BBL of oil per day, and averaged 585 BBL of oil per day. The wells are on hydraulic pump with a current combined rate of approximately 100 BBL of oil per day. Cumulative oil production to date is approximately 608 MBBL. There are currently no gas sales for the TMS wells.

Pecos County Wolfcamp Wells

During 2017, Contango embarked on a drilling program for Wolfcamp Shale wells in Pecos County, Texas. Five wells have been drilled and completed and are carried as proved developed producing (PDP) in this report. The five wells have a combined producing rate of approximately 1,150 BOPD and 2,550 MCFPD. Cumulative production to date is approximately 295 MBBL and 535 MMCF.

Reserves for the five wells are based on analysis of all available daily rate data from the wells. Four proved undeveloped (PUD) locations are assigned to each PDP well, with oil and gas reserve volumes equivalent to the specific offsetting PDP well.

OIL AND GAS PRICING

Projections of proved reserves contained in this report utilize constant product prices of $2.98 per MMBTU of gas and $51.34 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, as shown below in Table 2.

TABLE 2

**CONTANGO – PRODUCT PRICE DIFFERENTIALS
AND NGL YIELD BY FIELD**

Field	Oil/Cond Differential ($/BBL)	Residue Gas Differential ($/MMBTU)	Residue Gas Fraction after Fuel & NGL	NGL Yield (B/MM)	NGL Fraction of WTI Price
Eugene Island 10 (DMR)	-1.879	0.056	0.8767	27.303	0.491
Vermilion 170	0.340	-0.454	0.9286	21.150	0.518
Pecos County Wolfcamp	-4.389	-0.236	0.5500	134	0.351
HUFF 18-7H1-TMS	-1.157	-0.236	0.0695		
CMR Foster-TMS	-0.718	-0.236	0.0695		

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. Following is a brief description of the gross operating cost projections for each of the Contango properties:

According to the data analyzed, the ten Eugene Island 10 wells, including the Dutch 1-5 and Mary Rose 1-5 wells, had an average monthly operating cost of $779,326, or $77,933 per producing well. These wells produce to the ‘H Platform’ and are subject to product transportation and processing fees. These fees were calculated using LOE data and current processing contracts when supplied. For the Dutch wells, transportation and processing fees of $0.095 per net produced MCF, $2.196 per net barrel of oil, and $2.872 per net barrel of NGL were scheduled. For the Mary Rose wells, transportation and processing fees of $0.086 per net produced MCF, $1.975 per net barrel of oil and $2.583 per net barrel of NGL were scheduled.

For Vermilion 170, a fixed monthly operating cost of $156,815 was scheduled. Transportation and processing fees of $0.044 per net MCF of produced gas, $2.679 per net barrel of oil, and $5.639 per net barrel of NGL were also scheduled.

The fixed monthly operating cost for the Tuscaloosa Marine Shale wells in the CMR Foster Field were determined to be $22,630 per well. The monthly well operating cost for the Huff 18-7H1 was determined to be $21,042.

10 months of operating cost data were available for the four Pecos County Wolfcamp wells. The per well operating cost was calculated to be $15,000 using data provided through August of 2017. These wells were new drills in 2017 and more recent data indicates that monthly well operating costs will be closer to $7,000 per well. Per well operating costs were scheduled at $15,000 per month for the first 12 months and then $7,000 per month for the remaining well life. Transportation and processing costs of $0.375 per net produced MCF and $2.611 per net produced barrel of NGL were also scheduled.

CAPITAL COSTS

There are no future development projects scheduled for the Contango offshore properties. However, abandonment costs, as provided by Contango, have been scheduled. Platform abandonment costs are net of anticipated salvage value. No salvage value for the individual wells has been considered.

The development costs for each Pecos County PUD location was scheduled at nine million dollars. This value was provided by Contango, and is consistent with our experience in the area.

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 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

Exhibit 99.2

February 1, 2018

Mr. Jay S. Mengle
Contango Oil & Gas Company
717 Texas Avenue, Suite 2900
Houston, Texas 77002

Dear Mr. Mengle:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Contango Oil & Gas Company (Contango) interest in certain oil and gas properties located in Louisiana, Mississippi, Texas, and Wyoming. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 31 percent of all proved reserves owned by Contango. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, *Extractive Activities—Oil and Gas, except that future income taxes are excluded for all properties and, as requested, per-well overhead expenses are excluded for the operated properties and abandonment costs have not been included in our estimates of future net revenue.* Definitions are presented immediately following this letter. This report has been prepared for Contango's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Contango interest in these properties, as of December 31, 2017, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	1,574.6	795.4	10,696.9	56,478.0	38,011.7
Proved Developed Non-Producing	206.7	529.8	8,439.5	22,652.6	14,641.1
Proved Undeveloped	2,488.2	427.9	3,088.8	49,744.5	24,424.9
Total Proved	4,269.5	1,753.1	22,225.2	128,874.9	77,077.7

Totals may not add because of rounding.

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

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any values that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

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

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average West Texas Intermediate posted price of $47.79 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.976 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $47.84 per barrel of oil, $12.05 per barrel of NGL, and $2.784 per MCF of gas.

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

Capital costs used in this report were provided by Contango and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

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

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Contango interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Contango receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

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

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

The data used in our estimates were obtained from Contango, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Chad E. Ireton, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2012 and has over 11 years of prior industry experience. Mike K. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

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

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

By: /s/ Chad E. Ireton
Chad E. Ireton, P.E. 115760
Vice President

Date Signed: February 1, 2018

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: February 1, 2018

CEI:BCW

DEFINITIONS OF OIL AND GAS RESERVES

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

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

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

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

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

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

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

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

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

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

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

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

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

DEFINITIONS OF OIL AND GAS RESERVES

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

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

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

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

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

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

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

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

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

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

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

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

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

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

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

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

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

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

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

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

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

DEFINITIONS OF OIL AND GAS RESERVES

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

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

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

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

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

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90%

probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

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

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

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

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

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

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

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

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

DEFINITIONS OF OIL AND GAS RESERVES

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

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

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

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

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.
Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment`t (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

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

Exhibit 99.3

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 12, 2018

Mr. John P. Atwood
Senior Vice President
Exaro Energy III, LLC
1800 Bering Drive, Suite 540
Houston, Texas 77057

Re: Engineering Evaluation
Estimate of Reserves & Revenues
SEC Year End 2017 Pricing
"As of" January 1, 2018

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 and Probable reserves, "As of" January 1, 2018, is as follows:

SEC Year End 2017 Pricing	Net to Exaro Energy III, LLC						
	Proved Dev. Producing			Proved Dev. Non Producing	Proved Undeveloped	Total Proved	Total Probable
	New Wells	Old Wells	Total				
Reserve Estimates							
Oil/Cond., Mbbl	408.6	468.2	876.9	2.0	11.6	890.4	51.4
Gas, MMcf	30,851.9	45,883.8	76,735.7	302.3	820.2	77,858.2	3,930.3
Gas Equivalent, MMcfe	33,303.7	48,693.1	81,996.8	314.1	889.7	83,200.6	4,238.6
Revenues							
Oil, $ (15.6)%	19,978,422	22,904,846	42,883,272	96,467	566,004	43,545,744	2,511,948
Gas, $ (84.4)%	90,656,968	140,924,896	231,581,824	928,397	2,410,252	234,920,528	11,549,145
Total, $	110,635,390	163,829,742	274,465,096	1,024,864	2,976,256	278,466,272	14,061,093
Expenditures							
AdValorem Taxes, $	4,673,126	8,218,529	12,891,654	51,412	125,714	13,068,781	593,926
Severance Taxes, $	4,668,813	8,469,995	13,138,808	52,985	125,598	13,317,391	593,378
Direct Operating Expense, $	28,425,796	54,550,444	82,976,248	0	431,772	83,408,032	2,077,098
Variable Operating Expense, $	21,345,188	32,066,326	53,411,522	229,483	539,466	54,180,465	2,629,997
Total, $	59,112,923	103,305,294	162,418,232	333,880	1,222,550	163,974,669	5,894,399
Investments							
Capital, $	1,651,635	4,545,716	6,197,350	214,759	897,219	7,309,328	4,938,374
Estimated Future Net Revenues(FNR)							
Undiscounted FNR	49,870,828	55,978,712	105,849,536	476,225	856,487	107,182,240	3,228,322
FNR Disc. @ 10%	29,444,204	36,033,368	65,477,572	217,699	299,577	65,994,848	397,891
Allocation Percentage by Classification							
FNR Disc. @ 10%	44.6%	54.6%	99.2%	0.3%	0.5%	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 and Probable 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 – Securities and Exchange Commission (SEC) Regulation S-X 210, Rule 4-10 and Regulation S-K 229, Item 1200 (as revised in December 2008, effective 1-1-10), and Financial Accounting Standards Board (FASB) Statement No. 69 require oil and gas reserve information to be reported by publicly held companies as supplemental financial data. These regulations and standards provide for estimates of Proved reserves and revenues discounted at 10% and based on unescalated prices and costs. Revenues based on alternate product price scenarios may be reported in addition to the current pricing case. Reporting probable and possible reserves is optional. Probable and possible reserves must be reported separately from proved reserves.

The Society of Petroleum Engineers (SPE) requires Proved reserves to be economically recoverable with prices and costs in effect on the "as of" date of the report. In conjunction with the World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), the SPE has issued *Petroleum Resources Management System* (**2007 ed.**), which sets forth the definitions and requirements associated with the 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,* which sets requirements for the qualifications and independence of reserve estimators and auditors.

The estimated Proved and Probable reserves herein have been prepared in conformance with all SEC, SPE, WPC, AAPG, and SPEE definitions and requirements.

Projections – The reserve and revenue projections represented herein are on a calendar year basis, with the first time period beginning January 1, 2018 and ending December 31, 2018.

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. Jonah Energy has several rigs running in the northern part of the field close to Exaro's northern acreage blocks. Jonah Energy has submitted permits for eight vertical locations within section 11 and plans to begin drilling these locations in August 2018 according to Exaro. Due to the uncertainty of timing for the remaining locations in Exaro's acreage, 19 economic vertical locations have been categorized as Probable with the first one proposed to be drilled in December 2018.

Within the Proved Developed Non Producing (PNP) reserves category, Jonah Energy and Exaro have scheduled 42 currently producing wells for artificial lift enhancement. The goal is to lower tubing closer to the active perfs of each well to more efficiently lift the produced liquids. The total gross cost of each will be approximately $24,750 and the average expected reserve uplift around 45 MMcf. W.D. Von Gonten & Co. was able to calculate the reserve uplift based on wells with tubing lowered in 2016 and 2017.

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.

Exaro has divided the Jonah field into three areas based on location and production performance characteristics. The Updip area covers the western portion of Exaro's acreage. The Downdip area covers the central and northern acreage. The Antelope area covers the acreage in the eastern portion of the field. Since the signing of the original EDA, Encana drilled 159 wells in the Jonah field. These wells were spread across the Antelope, Downdip, and Updip areas of the field. W.D. Von Gonten & Co. originally developed three type curves for these areas. Due to an increasing amount of production history, W.D. Von Gonten & Co. decided to further divide the Updip and Antelope sections into several parts and adjust the type curves as necessary.

At the beginning of 2014, Jonah Energy drilled a horizontal well in section 29 of the Antelope area. It is currently producing at a gross rate of 1.64 MMcf/day with an EUR of 8.5 Bcf. Mid 2015, a second horizontal with a longer lateral and more frac stages was drilled to the north of the original horizontal well. The horizontal portion was drilled approximately 400' below the original and is only producing at a gross rate of 0.43 MMcf/day.

In March 2017, Jonah Energy brought an additional horizontal well online. Exaro has 2.42% working interest in this well. This well came online at a gross rate of 11.2 mmcf/day and has an estimated EUR of 9.0 Bcf. Due to the apparent success of the well, Jonah Energy plans to drill additional horizontal locations within the area. Two of these proposed locations are classified as Proved and have been drilled but are awaiting completion. There are three additional horizontal locations classified as Probable due to the lack of proximity to production.

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 17 wells located in section 35 and named the project 10-35. 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 projects throughout the updip and antelope sections. Though other similar projects are reportedly planned, there are no future projects scheduled in this report. As Exaro is not the operator of the field, and therefore has no control over the implementation of such projects, intent and/or timing cannot be determined.

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, 2018.

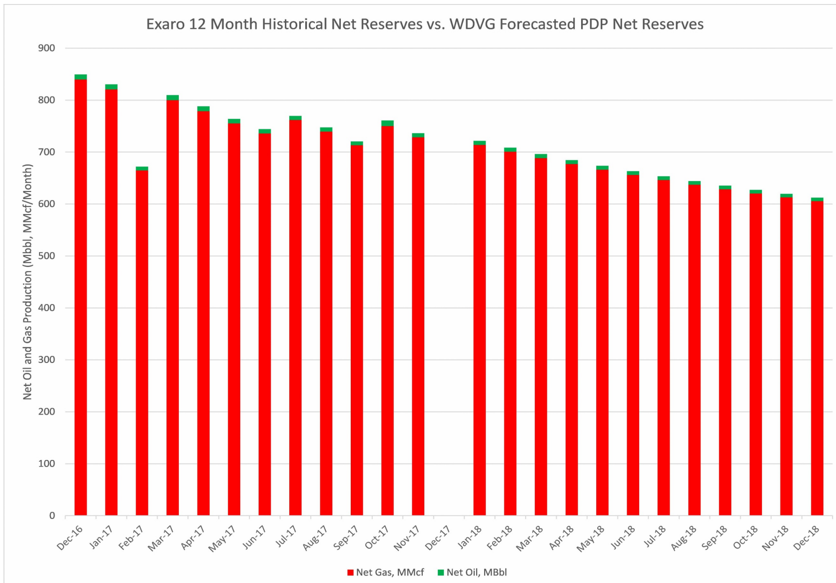


Figure 1: Historical Net Production and PDP Reserves Forecast as of January 1, 2018

Figure 2 below is a graphical comparison of Exaro's December 2016 through November 2017 historical net revenue and W.D. Von Gonten & Co.'s forecasted net revenue beginning January 2018.

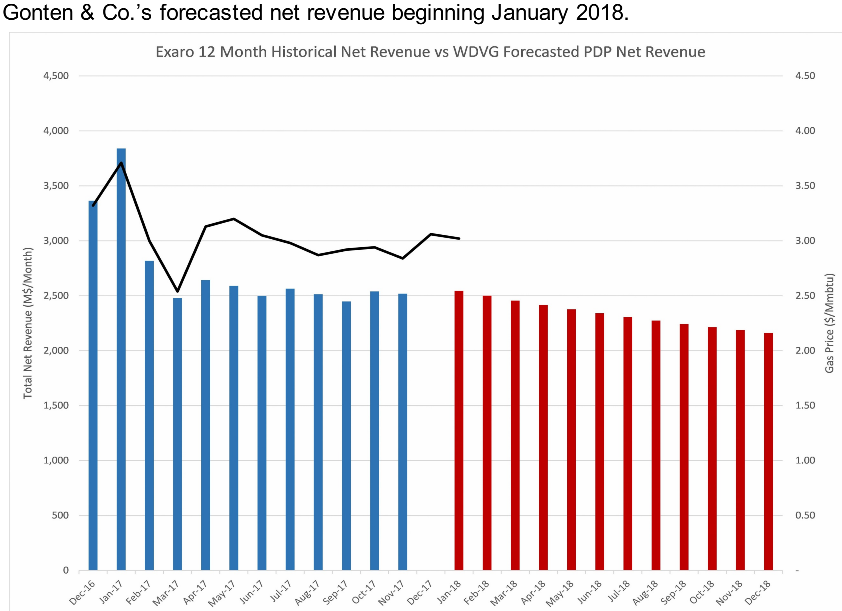


Figure 2: Historical Net Revenue and Forecasted Net Revenue as of January 1, 2018

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 the actual cost 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 $51.34 per barrel of oil and $3.02 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 of December 2016 through November 2017.

Figures 3 and 4 illustrate the comparison between historical differentials versus what is being projected.

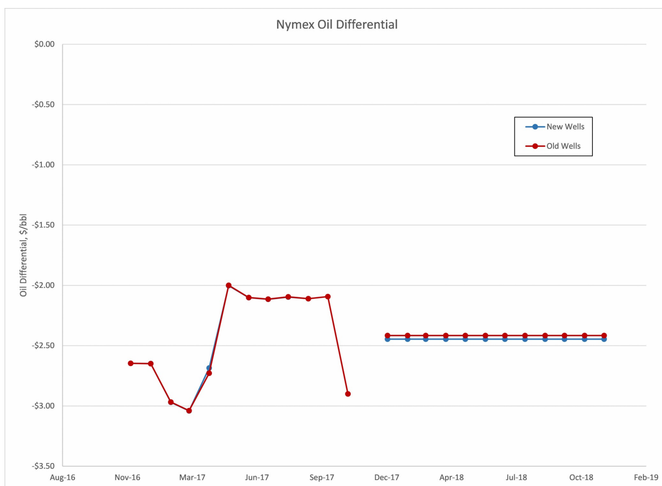


Figure 3: Historical and Forecasted Oil Differential

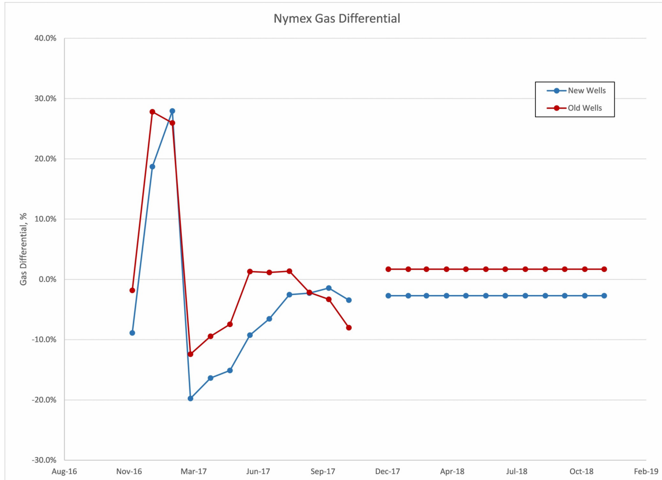


Figure 4: Historical and Forecasted Gas Differential

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 revenue or fees.

Operating Expenses and Capital Costs Discussion

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 of December 2016 through November 2017. Using the supplied data, W.D. Von Gonten & Co. applied a gross direct expense to each well based on its classification of new or old. If the well was involved in a line pressure reduction project, the operating expenses include additional fees. The horizontal wells also have an increased monthly expense compared to vertical wells based on historical numbers. All wells have a gross variable revenue deduct of $0.46 per Mcf which covers gathering fees. In addition, all wells have a gross $4.16/bbl salt water disposal (SWD) variable expense. 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 December 2016 through November 2017 versus comparable forecasted expenses for the twelve month calendar year 2018. April and October 2017 are irregularly high due to property taxes.

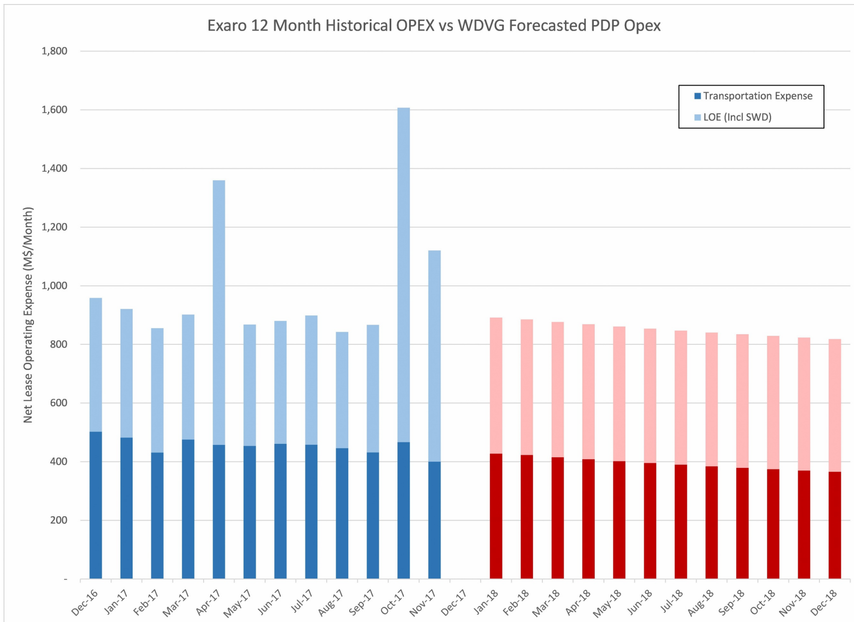


Figure 5: Historical and Forecasted Lease Operating Expense

Capital costs necessary to perform well completion operations and to drill undeveloped locations were supplied by Exaro. These costs were not verified from actual recent work in the area of interest, and therefore W.D. Von Gonten & Co. expresses no warranties as to the accuracy or reasonableness of these assumptions.

Other Considerations

Abandonment Costs – 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 Exaro's estimates regarding abandonment. A third party study would be necessary in order to accurately estimate all future abandonment liabilities.

Data Sources – 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.

Context – 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 estimated oil and gas volumes represented herein. 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 reserve 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.

Thank you for the opportunity to assist Exaro Energy III, LLC with this project.

Respectfully submitted,

Phillip R. Hunter

STATE OF TEXAS
PHILLIP R. HUNTER
96590
LICENSED
PROFESSIONAL ENGINEER

W.D.Von Gonten&Co.
Petroleum Engineering
TX Lic # F-1855

Phillip Hunter, P.E.
TX #96590

Jamie Foster

Jamie Foster

Reviewed by:

W.D. Von Gonten Jr.

W.D. Von Gonten, Jr., P.E.
TX #73244

I:/data/company/reports/client_letters/Miscellaneous\Exaro Energy III - SEC 01-2018.doc