2018 ANNUAL REPORT

LONESTAR®
RESOURCES

Dear Lonestar Shareholders:

2018 was most successful year in your Company's history. The Company continues to gain momentum in all aspects of its business. 2018 was a year of transformational growth in production, EBITDAX and reserves, and underpinned by a successful refinancing of our unsecured debt, extending the maturity of that component of our capital structure into 2023. Driven by our technologically differentiated approach to the Eagle Ford Shale, Lonestar drilled precedent-setting wells at its Horned Frog, Hawkeye and Karnes County properties. The results of these wells demonstrate outstanding internal rates of return, and we currently envision the bulk of our capital program being focused on these areas in 2019 and 2020. With the equity markets for energy equities in disarray, our focus will be on generating high returns on investment while increasing production and EBITDAX at rates in excess of 20%, with a goal of accomplishing these objectives with internally generated cash flow. If we are successful in accomplishing these objectives, I believe the stock market will ultimately recognize our success with meaningful appreciation in Lonestar's share price.

Review of Substantial Accomplishments for 2018

Lonestar reported average net oil and gas production of 11,154 Boe/d for the year ended December 31, 2018, an increase of 72% compared to 6,475 Boe/d for the year ended December 31, 2017. Growth in production, combined with better commodity price realizations and cost control allowed Lonestar to report a 100% increase in Adjusted EBITDAX for the year ended December 31, 2018 of $130.2 million, compared to $65.0 million for the year ended December 31, 2017.

Outstanding drilling results and the acquisition of properties in DeWitt County, Texas ("Sooner") were the driving forces behind a 27% increase in Proved reserves. In 2018, Lonestar added a total of 23.8 MMBOE, which consisted of 11.3 MMBOE through acquisitions, 8.3 MMBOE through extensions and discoveries, and 4.3 MMBOE through positive reserve revisions. These reserve additions were equivalent to 586% of Lonestar's 2018 production.

At December 31, 2018 Lonestar's proved reserves are comprised of 53.4 million barrels of crude oil and condensate, 19.9 million barrels of natural gas liquids ("NGL's"), and 120.2 billion cubic feet of natural gas. By energy content, Lonestar's proved reserves are weighted 79% to crude oil, condensate and NGL's. Using SEC guidelines, the PV-10 of Lonestar's Proved reserves increased 111% to over $1.1 billion. Lonestar's Proved Developed reserves increased 47% to 26.8 MMBOE and the PV-10 associated with its Proved Developed reserves increased 81% to $464.9 million using SEC guidelines.

Lonestar's capital expenditures totaled $217.0 million for the year ended December 31, 2018, yielding Proved all-sources finding and development costs of $9.12 per BOE. Drillbit-only finding and developing costs averaged $13.60 per BOE. 2018 continues a long-standing record of outstanding performance metrics. Including 2018 results, Lonestar's five-year reserves replacement ratio has been 716% and the five-year all-sources F&D cost averaged $8.94 per BOE.

In 2018, Lonestar's Proved & Probable reserves increased 31% to 121.5 MMBOE, which is comprised of 67.4 million barrels of crude oil and condensate, 27.0 million barrels of natural gas liquids, and 162.7 billion cubic feet of natural gas. Using SEC guidelines, PV-10 for Proved & Probable reserves exceeds $1.3 billion.

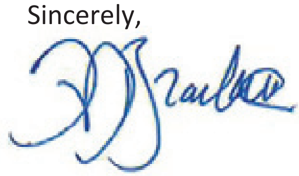
Lonestar's Proved & Probable reserves included 261 drilling locations which were assigned reserves by the Company's independent petroleum engineers, equating to approximately 15 years of drilling activity at Lonestar's current rate of drilling.

Lonestar's progress was not limited to its operations. The Company substantially improved its financial position. In January, the Company closed its offering of $250 million 11.250% senior notes due 2023. These notes replaced our 8 ¾% notes due April 2019, and significantly extend our debt maturity schedule. Additionally, during the course of the year ended December 31, 2018, we increased our Borrowing Base from $160 million to $275 million at year-end.

As we look forward to 2019 and beyond, Lonestar is positioned to grow meaningfully and become increasingly profitable. Our 2019 capital program is expected to generate significant growth in production and EBITDAX over the course of the year. A bigger Lonestar will be a more profitable company, and better positioned to take advantage of what we believe will be an extremely active market for producing properties in the Eagle Ford Shale play.

I also want to thank our employees in the office and the field for their dedication, hard work and creativity that have helped Lonestar through the downturn and through our transition. Lastly, I want to express my profound gratitude to our Board of Directors for their wisdom, guidance and support.

Sincerely,



Frank D. Bracken, III
Chief Executive Officer.

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, 2018

OR

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

For the transition period from ___________ to _________

Commission File Number 001-37670

Lonestar Resources US Inc.

(Exact name of Registrant as specified in its Charter)

Delaware	**81-0874035**
(State or other jurisdiction of incorporation or organization)	***(I.R.S. Employer Identification No.)***
111 Boland Street, Suite 301, Fort Worth, TX	**76107**
(Address of principal executive offices)	***(Zip Code)***

Registrant's telephone number, including area code: **(817) 921-1889**

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

Title of Each Class	Name of Exchange on Which Registered
Class A Voting Common Stock, par value $0.001 per share	NASDAQ Global Select Market

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 15(d) of the Act. YES ☐ NO ☑

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) 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 definition of "large accelerated filer", "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☑

The aggregate market value of the registrant's Class A voting common stock held by non-affiliates, based on the closing price of the registrant's Class A voting common stock as of the last business day of the registrant's most recently completed second fiscal quarter, was approximately $133.9 million.

The number of shares of the Registrant's Class A voting common stock outstanding as of March 7, 2019 was 24,773,643.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the Registrant's 2019 Annual Meeting of Shareholders are incorporated by reference into Part III of this Annual Report on Form 10-K.

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GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this section are used throughout this Annual Report on Form 10-K:

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

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"*Bbl/d*." One stock tank barrel of crude oil, condensate or natural gas liquids per day.

"*BOE*." One barrel of oil equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to 6 Mcf of natural gas.

"*BOE/d*." BOE's produced per day.

"*British thermal unit*" or "*Btu*." The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit (?).

"Class A common stock." Class A voting common stock of Lonestar Resources US Inc., par value $0.001 per share.

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

"*gross acres*" or "*gross wells*." The total acres or wells, as the case may be, in which an entity owns a working interest.

"*held by production*" or "*HBP*" Acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or gas.

"*horizontal drilling*." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*IRS*." Internal Revenue Service.

"*LIBO rate*." London Interbank Offered rate.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*MBOE*." One thousand barrels of oil equivalent.

"*Mcf*." One thousand cubic feet of natural gas.

"*Mcf/d*." One thousand cubic feet of natural gas per day.

"*MMBbls*." One million stock tank barrels, of 42 U.S. gallons liquid volume, used in reference to crude oil, condensate or natural gas liquids.

"*MMBOE*." One million barrels of oil equivalent.

"*MMBtu*." One million British thermal units.

"*MMcf*." One million cubic feet of natural gas.

"*natural gas liquids*" or " *NGLs*." The combination of ethane, propane, butane, isobutane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

"*net acres*" or "*net wells*." The percentage of total acres or wells, as the case may be, an owner has out of a particular number of gross acres or wells. For example, an owner who has 50% interest in 100 gross acres owns 50 net acres.

"*net revenue interest*." An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

"*NYMEX*." The New York Mercantile Exchange.

"*present value of future net revenues*" or "*PV-10*." PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows. PV-10 differs from the Standardized Measure because it does not include the effect of future income taxes.

"*proved developed reserves*." Proved reserves 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 with the cost of a new well; or

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.

"*proved reserves*." Those quantities of oil and natural 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. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

"*proved undeveloped reserves*" or "*PUDs*." Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

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

"*reserves.*" Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development prospects 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 natural gas or related substances to market and all permits and financing required to implement the project.

"*reservoir.*" A porous and permeable underground formation containing a natural accumulation of producible hydrocarbons that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"*SEC.*" The United States Securities and Exchange Commission.

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

"*WTI.*" West Texas Intermediate crude oil, which is a light, sweet crude oil, characterized by an American Petroleum Institute gravity, or API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a benchmark for other crude oils.

Cautionary Statement Regarding Forward-Looking Statements

This annual report contains statements concerning our intentions, expectations, projections, assessments of risks, estimations, beliefs, plans or predictions for the future, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements include, among others, statements regarding:

- our growth strategies;
- our ability to explore for and develop oil and gas resources successfully and economically;
- our drilling and completion techniques;
- our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities;
- our estimates regarding timing and levels of production;
- changes in working capital requirements, reserves, and acreage;
- commodity price risk management activities and the impact on our average realized prices;
- anticipated trends in our business and industry;
- availability of pipeline connections and water disposal on economic terms;
- effects of competition on us;
- our future results of operations;
- profitability of drilling locations;
- our reputation as an operator and our relationships and contacts in the market
- our liquidity and our ability to finance our exploration and development activities, including accessibility of borrowings under our senior secured credit facility, our borrowing base, and the result of any borrowing base redetermination;
- our planned expenditures, prospects and capital expenditure plan;
- future market conditions in the oil and gas industry;
- our ability to make, integrate and develop acquisitions and realize any expected benefits or effects of completed acquisitions;
- the benefits, effects, availability of and results of new and existing joint ventures and sales transactions;
- our ability to maintain a sound financial position;
- receipt of receivables, drilling carry and proceeds from sales;
- our ability to complete planned transactions on desirable terms; and
- the impact of governmental regulation, taxes, market changes and world events.

You generally can identify our forward-looking statements by the words “anticipate,” “believe,” budgeted,” “continue,” “could,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “may,” “objective,” “plan,” “potential,” “predict,” “projection,” “scheduled,” “should,” or other similar words. Such statements rely on assumptions and involve risks, uncertainties, and other important factors, many of which are beyond our control, including, but not limited to, those relating to a worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in oil and gas prices, the need to replace reserves depleted by production, operating risks of oil and gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, the timing and amount of borrowing base determinations (including determinations by lenders) and availability under our senior secured credit facility, evaluations of us by lenders under our senior secured credit facility, other actions by lenders, the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, oil and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, acquisition risks, availability of equipment and crews, actions by midstream and other industry participants, weather, our ability to obtain permits and licenses, the results of audits and assessments, the failure to obtain certain bank and lease consents, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture parties, results of exploration activities, the availability and completion of land acquisitions, costs of oilfield services, completion and connection of wells, our ability to adhere to our proposed drilling schedule, potential expiration of leases on undeveloped leasehold assets under certain conditions, and other important factors detailed in this annual report.

We have based our forward-looking statements on our management's beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the important factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under Part I, Item 1A. *Risk Factors* and in other sections of this annual report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on our forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and, except as required by law, we undertake no duty to update or revise any forward-looking statement.

Certain terms used herein relating to the oil and gas industry are defined in *Glossary of Certain Defined Terms* included above.

Presentation of Information

On July 5, 2016, Lonestar Resources US Inc., a Delaware corporation, acquired all of the issued and outstanding ordinary shares of Lonestar Resources Limited, the former parent company of the Lonestar group of companies, pursuant to a Scheme of Arrangement under Australian law that was approved by the Federal Court of Australia on June 28, 2016, and by Lonestar Resources Limited's shareholders at a meeting of shareholders, which approval was obtained in March 2016 (the "Reorganization"). The purpose of the Reorganization was to reorganize the operations of Lonestar Resources Limited, an Australian corporation, into a structure whereby the ultimate parent company of the Lonestar group of companies would be a Delaware corporation. In connection with the Reorganization, the ordinary shares of Lonestar Resources Limited were delisted from the Australian Securities Exchange, and the Class A common stock of Lonestar Resources US Inc. began trading on the Nasdaq Global Select Market on July 5, 2016 under the ticker symbol "LONE".

Lonestar Resources America, Inc. ("LRAI"), a subsidiary of Lonestar Resources Limited prior to the Reorganization, has been the U.S. operating company for the Lonestar group of companies since February 2013. Following the Reorganization, LRAI continued in the role of U.S. operating company for Lonestar Resources US Inc.

Unless the context otherwise requires, references to "Lonestar," "we," "us," "our," and "the Company" refer to (i) Lonestar Resources Limited and its subsidiaries prior to the Reorganization and (ii) Lonestar Resources US Inc. and its subsidiaries upon completion of the Reorganization, as applicable. General information about us can be found on our website at www.lonestarresources.com. The information available on or through our website, or about us on any other website, is neither incorporated into, nor part of, this report. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings that we make with the SEC, as well as any amendments and exhibits to those reports, will be available free of charge through our website as soon as reasonably practicable after we file or furnish them to the SEC. Information is also available on the SEC website at www.sec.gov for our U.S. filings.

PART I

Item 1. Business.

Overview

Lonestar is an independent oil and natural gas exploration and production company focused on the exploration, development and production of unconventional oil, natural gas liquids and natural gas in the Eagle Ford Shale (the "Eagle Ford") in South Texas.

We have accumulated approximately 78,193 gross (57,491 net) acres as of December 31, 2018. We operate in one industry segment, which is the exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operational activities and consolidated revenues are generated from markets exclusively in the United States, and, as of December 31, 2018, we had no long-lived assets located outside the United States.

Our primary operational focus is on our Eagle Ford position in eleven Texas counties, and our properties in the Eagle Ford are divided into three distinct regions: the Western Eagle Ford (comprised of Dimmit, La Salle and Frio Counties), Central Eagle Ford (comprised of Gonzales, Karnes, Fayette, Wilson, DeWitt and Lavaca Counties) and Eastern Eagle Ford (comprised of Brazos and Robertson Counties). As of December 31, 2018, we operated 85% of our Eagle Ford position and approximately 95% of our acreage was held by production, or HBP. Third-party engineers have identified 273 gross (204 net) horizontal drilling locations on our Eagle Ford acreage.

We currently plan to invest the majority of our 2019 capital budget in the horizontal development of our Eagle Ford properties and have allocated between $107 million and $130 million to drilling and completion activities to develop these assets. We have historically grown our Eagle Ford leasehold position through organic leasing activities, farm-ins, acquisitions, and other structures. We believe our management team's extensive experience and our reputation as an operator in the basin provide us with relationships and contacts that could serve as a platform for expanded opportunities to grow our acreage footprint.

We seek to deploy advanced drilling, completion and production techniques across our unconventional acreage with a goal of minimizing completed well costs and maximizing per-well hydrocarbon recoveries. Increasingly, we utilize 3-D seismic imaging to plan our lateral programs while utilizing log-based petrophysical analysis to optimize our drilling targets within distinct horizons within the Eagle Ford section. We are also frequently drilling laterals in excess of 7,000 feet in an effort to maximize per-well recoveries and economic returns. Further, we are utilizing thru-bit logging in our laterals to design non-geometric completions which allow for the use of diverters while increasing proppant concentrations in an effort to make our fracture stimulations more effective. Additionally, we employ active choke management to optimize pressure drawdowns in an effort to maximize liquid hydrocarbon recoveries.

The following table presents summary data for each of our primary project areas as of December 31, 2018:

	Gross Acreage	Net Acreage	Average Working Interest	Identified Drilling Locations (1)(2)		Producing Wells		Average Daily Production BOE/d	Capex 2019	Planned Wells (Net) (3) 2019
				Gross	Net	Gross	Net			
Eagle Ford										
Western	16,028	14,340	89%	49	45	65	63	5,773	35%	6.9
Central	50,394	35,830	71%	193	139	193	151	5,024	61%	11.2
Eastern	11,771	7,321	62%	31	20	26	17	358	4%	0.5
Total	78,193	57,491	74%	273	204	284	231	11,155	100%	18.6

(1) Potential drilling locations are identified based on analysis of relevant geologic and engineering data. Our total identified drilling locations include 177 gross (143 net) locations that were associated with proved undeveloped reserves, or PUDs, as of December 31, 2018. The remaining drilling locations were not associated with proved reserves as of December 31, 2018, however, based on our analysis of our drilling results, the drilling results of offset operators and applicable geologic and engineering data, we believe these locations are prospective for development.

(2) The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in our adding additional proved reserves to our existing reserves. See *Risk Factors*. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

(3) Planned Wells (Net) represents our optimal planned drilling results based on our currently budgeted capital expenditures.

The following table presents the number of productive oil and gas wells attributable to the Company's project areas as of December 31, 2018:

	Oil Producing Wells		Gas Producing Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Eagle Ford						
Western	57	57	8	6	65	63
Central	193	151	—	—	193	151
Eastern	26	17	—	—	26	17
Total	276	225	8	6	284	231

Our Properties

Our Eagle Ford area net production for the year ended December 31, 2018 was 11,155 BOE/d, comprised of 6,805 Bbls/d of oil, 2,239 Bbls/d of NGLs and 12,665 Mcf/d of natural gas, from 284 gross (231 net) producing wells.

In June 2017, we significantly expanded our operations in the Central Eagle Ford by acquiring oil and gas properties in Karnes, Gonzales, Lavaca and Fayette Counties, Texas in two separate transactions totaling $109.8 million. The acquisitions included approximately 30,219 gross acres (21,238 net acres), and at the time we completed the acquisitions, our net acreage increased by 59% to approximately 57,172 net acres.

In November 2018, we acquired additional oil and gas properties in the Central Eagle Ford in DeWitt County for $38.7 million, before closing adjustments, from Sabine Oil & Gas Corporation and Alerion Gas AXA, LLC. The acquisition, which is 95% operated, included approximately 3,071 gross acres (2,693 net acres) and approximately 800 BOE/d of production from 20 producing wells on the date of the acquisition.

As of December 31, 2018, according to our reserve report, our Eagle Ford properties had proved reserves of 93.4 MMBOE, of which 79% was crude oil and NGLs and 29% was proved developed producing, or PDP. The Standardized Measure of our proved reserves as of December 31, 2018 was $980.1 million, and the PV-10[(1)] of our proved reserves as of December 31, 2018 was $1,139.5 million using SEC pricing, and 41% of such PV-10 was PDP. See *Oil and Natural Gas Data* below for more information.

Third-party engineers have identified 273 gross (204 net) horizontal drilling locations on our acreage, of which 62% are expected to be drilled using lateral lengths of or greater than 7,000 feet and 88% are expected to be drilled using lateral lengths of, or greater than, 5,000 feet.

Western Eagle Ford. As of December 31, 2018, our Western Eagle Ford region was comprised of 16,028 gross (14,340 net) acres in Dimmit, La Salle and Frio Counties. As of December 31, 2018, we operated 100% of this acreage, and approximately 95% of this net acreage was HBP. We plan on allocating 35% of our 2019 capital budget to our Western Eagle Ford acreage.

Central Eagle Ford. Our Central Eagle Ford region, as of December 31, 2018, was comprised of 50,394 gross (35,830 net) acres in Gonzales, Karnes, Fayette and Wilson Counties. As of December 31, 2018, we operated 82% of this acreage, and approximately 97% of this net acreage was HBP. We plan on allocating 61% of our 2019 capital budget to this area.

Eastern Eagle Ford. Our Eastern Eagle Ford region, as of December 31, 2018, was comprised of 11,771 gross (7,321 net) acres in Brazos and Robertson Counties. Approximately 86% of this net acreage was HBP, and as of December 31, 2018, we operated 64% of this acreage. We plan on allocating 4% of our 2019 capital budget to our Eastern Eagle Ford acreage.

(1) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from the Standardized Measure because it does not include the effect of future income taxes. See *Oil and Natural Gas Data—PV-10* below for more information and a reconciliation of PV-10 to our Standardized Measure.

Business Strategies

Our primary business objective is to increase reserves, production and cash flows at attractive rates of return on invested capital. We are focused on exploiting long-lived, unconventional oil, NGLs and natural gas reserves from the Eagle Ford Shale in South Texas. Key elements of our business strategy include:

- ***Develop our Eagle Ford leasehold positions***. We intend to continue developing our acreage position to maximize the value of our resource potential and generate returns for our stockholders through continuing to utilize best-in-class drilling and completion techniques at the lowest possible costs. Through the conversion of our resource base to developed reserves, we will seek to increase our production and cash flow, thereby increasing the value of our reserves. As of December 31, 2018, we were producing from 284 gross (231 net) Eagle Ford wells and we intend to deploy all our capital budget for 2019 on the development of our Eagle Ford acreage.

- ***Pursue organic leasing, strategic acquisitions, and other structures to continue to develop and grow our production and leasehold position***. We believe that we will be able to continue to identify and acquire additional acreage and producing assets in the Eagle Ford. By leveraging our longstanding relationships in this area, we intend to expand our Eagle Ford acreage. We also intend to continue to find creative ways to fund our continued development while maintaining financial discipline and seeking to maximize returns from our projects. We have successfully used farm-ins and drilling commitments as means of adding prospective Eagle Ford acreage by committing to drilling activity as opposed to deploying capital with lease acquisition costs. For example, in the past we have executed on this strategy through our Joint Development Agreement with IOG Capital L.P. (“IOG”). This agreement allowed for working interest-level participation with IOG participating on a promoted basis for funding farm-ins. This was a wellbore-only agreement that allowed us to develop acreage or hold expiring acreage while maintaining some upside through a specified return hurdle earn-in and all of the upside associated with future development of offsetting wells.

- ***Leverage our extensive operational expertise and concentration of our operating areas to reduce costs and enhance returns***. We are focused on continuously improving our operating measures. We intend to leverage the magnitude and concentration of our acreage within the Eagle Ford in our operating areas, as well as our experience within our areas of operation to capture economies of scale, including multiple-well pad drilling, and utilizing centralized production and fluid-handling facilities. Our management and operating team has significant industry and operating experience, and it regularly evaluates our operating measures against those of other operators in our area in order to improve our performance and identify additional opportunities to optimize our drilling and completion techniques and make informed decisions about our capital expenditure program and drilling activity.

- ***Maintain operational control over our drilling and completion operations***. We operate 85% of the Eagle Ford wells in which we have a working interest and intend to maintain a high degree of operational control over substantially all of our producing locations. We believe that continuing to exercise a high degree of control over our acreage position will provide us with flexibility to manage our drilling program and optimize our returns and profitability.

- ***Maintain and enhance financial liquidity and flexibility***. We intend to use cash on hand and borrowings from our revolving credit facility, combined with our cash flow from operations, to continue executing a capital expenditure program that we believe will help us achieve steady growth of production, cash flow and proved reserves. Furthermore, we intend to continue to employ a hedging strategy on our PDP production to achieve more predicable cash flow and to reduce our exposure to adverse fluctuations in oil, NGLs and natural gas prices. We regularly assess the futures markets for opportunities to enter into additional hedging contracts. Generally, we have entered into additional hedges when we believe that they are additive to our borrowing base and/or lock-in rates of return which exceed our hurdle rates. Further, we have strived to enter into unique and strategically-effective arrangements to reduce our outstanding indebtedness and improve our financial liquidity. We intend to continue to seek out such opportunities to improve our balance sheet and financial flexibility.

Our Competitive Strengths

We possess a number of competitive strengths that we believe will allow us to successfully execute our business strategies.

- ***Geographic focus in one of North America's leading unconventional oil plays***. We have assembled a leasehold position of 57,491 net acres in the Eagle Ford as of December 31, 2018. We believe this unconventional oil and natural gas formation has one of the higher rates of return among such formations in North America. In addition to leveraging our technical expertise in our project areas, our geographically-concentrated acreage position allows us to establish economies of scale with respect to drilling, production, operating and administrative costs. Based on our drilling and production results and well-established offset operator activity in and around our project areas, we believe there are relatively low geologic risks and ample repeatable drilling opportunities across our core operating areas in the Eagle Ford where we have devoted all of our 2019 drilling capital budget.

- ***Experienced management team***. Our top eight executives average 30 years of industry experience. We have assembled what we believe to be a strong technical staff of geoscientists, field operations managers and engineers with significant experience drilling horizontal wells including fracture stimulation of unconventional formations, which has resulted in reserve and production growth. In addition, our management team has extensive expertise and operational experience in the oil and natural gas industry with a proven track record of successfully negotiating, executing and integrating acquisitions. Members of our management team have previously held positions with major and large independent oil and natural gas companies.

- ***Demonstrated ability to increase acreage position and drive growth of oil production and reserves***. We have increased our Eagle Ford net acreage by over fifteen times, from 3,710 net acres in 2011 to 57,491 net acres as of December 31, 2018. We placed 21 gross (18.3 net) and 12 gross (11.3 net) Eagle Ford wells onstream during 2018 and 2017, respectively. We had a total of 284 gross (231 net) producing wells in the Eagle Ford, as of December 31, 2018. Our average total production for 2018 was 11,155 BOE/d, of which 100% was from the Eagle Ford. Between December 31, 2017 and December 31, 2018, our total proved reserves increased by approximately 19.8 MMBOE, from 73.6 MMBOE to 93.4 MMBOE. Our proved developed reserves increased by approximately 8.6 MMBOE, from 18.3 MMBOE to 26.9 MMBOE. Our five-year average reserve replacement ratio is approximately 716%, which we believe demonstrates our ability to grow reserves year over year. We believe the location and concentration of our project areas within the Eagle Ford provide us an opportunity to continue to increase production, lower costs and further delineate our proved reserves.

- ***Demonstrated ability to adapt and employ leading drilling and completion techniques***. We are focused on enhancing our drilling, completion and production techniques to maximize recovery of hydrocarbons. Industry techniques, with respect to drilling and completion, have significantly evolved over the past several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of longer laterals and more tightly-spaced fracture stimulation stages. We continuously evaluate industry results and methods and monitor the results of other operators to improve our operating practices, and we expect that our drilling and completion techniques will continue to improve and evolve. We have demonstrated a track record of innovation and operational improvement in the past through our partnership with Schlumberger, the Geo-Engineered Completion Alliance ("GECA"). This Alliance utilized a variety of technologies intended to focus our wells in precise, optimal intervals of the Eagle Ford and utilize analysis of advanced logs run through the laterals to assist in the design of non-geometric fracture stimulation stages, which in combination with diverters, were intended to stimulate a greater percentage of the lateral on a cost-effective basis. We continue to use these technologies which can be provided by several energy service companies.

- ***Multi-year drilling inventory in existing and emerging resource plays***. Third-party engineers have identified 273 gross (204 net) horizontal drilling locations on our Eagle Ford acreage. As of December 31, 2018, these identified drilling locations included 177 gross (143 net) locations to which we have assigned proved undeveloped reserves. We believe our acreage is prospective for additional locations and plan to continue evaluating this acreage and monitoring industry activity in order to maximize our efficiency in developing this acreage. Furthermore, we are evaluating our acreage to identify and develop additional locations across our portfolio as we evaluate down-spacing in the Eagle Ford and accessing other stratigraphic horizons that lie above and below the Eagle Ford, such as the Austin Chalk, Buda, Georgetown, Woodbine and Wilcox formations. We believe our multi-year drilling inventory and exploration portfolio will help provide near-term growth in our production and reserves and highlight the long-term resource potential across our asset base.

- ***Oil-weighted reserves and production***. Our net proved reserves at December 31, 2018 were comprised of approximately 57% crude oil, and our net average daily production for the year ended December 31, 2018 and 2017 was comprised of 61% oil and 67% crude oil, respectively. Given the current commodity price environment and resulting disparity between oil and natural gas prices on a per-BOE basis, we believe our high percentage of oil reserves, compared to our overall reserve base, is a key strength.

- ***Low field operating expenses***. Even in light of low oil prices, we expect to generate sufficient cash margins on the operation of our Eagle Ford acreage due to our low cash operating costs. For the year ended December 31, 2018, our total field operating expenses (including lease operating and gas gathering expenses of $6.39 per BOE, and production and ad valorem taxes of $2.71 per BOE) totaled $9.10 per BOE in our project areas.

- ***Hedging position***. As of December 31, 2018, we had in place hedges covering approximately 6,000 Bbls/d for 2019 at an average price of approximately $53.88 per Bbl. We believe that these hedges help insulate us from oil price volatility. In addition, we have in place additional hedges for 2020. Our 2020 oil derivative contracts currently consist of 2,680 Bbls/d at $56.97 per Bbl. Additionally, we have also entered into contracts to hedge our 2019 natural gas production, covering 15,000 MMBtu/d at a weighted average price of $3.78 per MMBtu for the first quarter of 2019 and 15,000 MMBtu/d at a weighted average price of $2.87 per MMBtu for the fourth quarter of 2019.

Oil and Natural Gas Data

Estimated Proved Reserves

The following table presents estimated net proved oil, NGLs and natural gas reserves attributable to our properties and the Standardized Measure amounts associated with the estimated proved reserves attributable to our properties as of December 31, 2018 and 2017. We employ a technical staff of engineers and geoscientists that perform technical analysis of each producing well and undeveloped location. The staff uses industry-accepted practices to estimate, with reasonable certainty, the economically producible oil and gas reserves. The practices for estimating hydrocarbons-in-place include, but are not limited to, mapping, seismic interpretation, core analysis, log analysis, mechanical properties of formations, thermal maturity, well testing and flowing bottom-hole pressure analysis. We employ an independent petroleum engineer to estimate 100% of our proved reserves. The data below is based on our reserve report prepared by W.D. Von Gonten & Co. The Standardized Measure and PV-10 amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31,	
	2018	2017
Estimated Proved Reserves(1)		
Oil (MBbls)	53,499	50,701
NGLs (MBbls)	19,869	10,875
Natural Gas (MMcf)	120,165	71,874
Total Estimated Proved Reserves (MBOE)(2)	93,396	73,555
Estimated Proved Developed Reserves		
Oil (MBbls)	15,459	12,657
NGLs (MBbls)	5,721	2,846
Natural Gas (MMcf)	34,388	17,034
Total Estimated Proved Developed Reserves (MBOE)(2)	26,912	18,342
Estimated Proved Undeveloped Reserves		
Oil (MBbls)	38,040	38,044
NGLs (MBbls)	14,147	8,029
Natural Gas (MMcf)	85,777	54,840
Total Estimated Proved Undeveloped Reserves (MBOE)(2)	66,484	55,213
Standardized Measure (millions)(3)	$ 980.1	$ 479.6
PV-10 (millions)(4)	$ 1,139.5	$ 538.3
Oil and Gas Prices Used(1) :		
Oil — NYMEX-WTI per Bbl	$ 65.56	$ 51.34
Natural Gas — NYMEX-Henry Hub per MMBtu	3.10	2.98

(1) Our estimated net proved reserves and related Standardized Measure were determined using index prices for crude oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of our properties. The prices are based on the average prices during the 12-month period prior to the ending date of the period covered, determined as the unweighted arithmetic average of the prices in effect on the first day of the month for each month within such period, unless prices were defined by contractual arrangements, before they are adjusted, by lease, for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead. NGL pricing used was approximately 40% of corresponding crude oil prices.

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

(3) Standardized Measure is calculated in accordance with Accounting Standards Codification ("ASC") Topic 932, *Extractive Activities — Oil and Gas*.

(4) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months (or constantly flat using the base commodity prices given for the flat pricing case). PV-10 differs from the Standardized Measure because it does not include the effect of future income taxes. See below for a reconciliation of Standardized Measure to our PV-10.

The data in the table above represent estimates only. Oil, NGLs and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil, NGLs and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil, NGLs and natural gas that are ultimately recovered.

Future prices realized for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The Standardized Measure amounts shown above should not be construed as the current market value of our estimated oil, NGLs and natural gas reserves. The 10% discount factor used to calculate Standardized Measure, which is required by Financial Accounting Standards Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

PV-10

Certain of our oil and natural gas reserve disclosures included in this Annual Report on Form 10-K are presented on a PV-10 basis. PV-10 is the estimated present value of the future cash flows, less future development and production costs from our proved reserves before income taxes, discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure because it does not include the effects of future income taxes, as is required in computing the Standardized Measure. We believe that the presentation of a pre-tax PV-10 value provides relevant and useful information because it is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and gas companies. Because many factors that are unique to each individual company may impact the amount and timing of future income taxes, the use of a pre-tax PV-10 value provides greater comparability when evaluating oil and gas companies. The PV-10 value is not a measure of financial or operating performance under U.S. GAAP, nor is it intended to represent the current market value of proved oil and gas reserves. The definition of PV-10 value, as defined above, may differ significantly from the definitions used by other companies to compute similar measures. As a result, the PV-10 value, as defined, may not be comparable to similar measures provided by other companies.

The following table provides a reconciliation of the Standardized Measure to PV-10:

	December 31,	
In millions	2018	2017
Standardized measure of discounted future net cash flows	$ 980.1	$ 479.6
Discounted estimated future income taxes	159.4	58.7
PV-10	$ 1,139.5	$ 538.3

Reconciliation of Proved Reserves

Our proved developed oil and natural gas reserves increased from 18.3 MMBOE at December 31, 2017, to 26.9 MMBOE at December 31, 2018, primarily due to the conversion of proved undeveloped to proved developed through our drilling program, which brought 21 gross wells online during 2018 and added 6.3 MMBOE of proved reserves. We also added 2.5 MMBOE from the Sooner Acquisition, which closed in November 2018 and added 20 producing wells. Our proved developed oil and natural gas reserves experienced revisions of 1.4 MMBOE primarily due to an increase in SEC pricing.

	Proved Developed Reserves (MBOE)
As of December 31, 2017	18,342
Extensions and discoveries	2,379
Purchases of minerals in place	2,527
Revisions of prior estimates	1,424
Production	(4,072)
Conversion of proved undeveloped to proved developed	6,312
As of December 31, 2018	26,912

Development of Proved Undeveloped Reserves

At December 31, 2018, our proved undeveloped reserves were approximately 66.5 MMBOE, an increase of approximately 11.3 MMBOE over our December 31, 2017 estimated proved undeveloped reserves of approximately 55.2 MMBOE. In 2018, we added proved undeveloped reserves of 5.9 MMBOE as a result of drilling and completion activities and 8.7 MMBOE as a result of the Sooner Acquisition. During 2018, approximately 6.3 MMBOE of proved undeveloped reserves, as of December 31, 2017, were converted to proved developed reserves as a result of drilling and completion activities during the year, and 3.0 MMBOE of reserves were added to our proved undeveloped reserves as a result of revisions in estimates from 2017. Revisions of previous estimates were added primarily due the increase in SEC pricing.

All PUD drilling locations are scheduled to be drilled prior to the end of 2023. The timing of our development schedule correlates with the projected increase in our production and the anticipated resulting free cash flow over the next five years.

	Proved Undeveloped Reserves (MBOE)
As of December 31, 2017	55,213
Extensions and Discoveries	5,880
Purchases of minerals in place	8,749
Sales of minerals in place	—
Revisions of prior estimates	2,954
Conversion of proved undeveloped to proved developed	(6,312)
As of December 31, 2018	66,484

Qualifications of Responsible Technical Persons

Internal Company Person. Thomas H. Olle, our Vice President-Reservoir Engineering, is the technical person primarily responsible for overseeing the preparation of our reserve estimates. Mr. Olle is also responsible for our interactions with and oversight of our independent third-party reserve engineers. Mr. Olle has more than 40 years of industry experience, with expertise in reservoir management and project development across a broad range of reservoir types. Mr. Olle previously held senior positions at Encore Acquisition Corp. and Burlington Resources. He holds a Bachelor of Science degree in Mechanical Engineering with Highest Honors from the University of Texas at Austin and is a member of the Society of Petroleum Engineers.

Independent Reserve Engineers. W.D. Von Gonten & Co. is an independent petroleum engineering and geological services firm. No director, officer or key employee of W.D. Von Gonten & Co. has any financial ownership in Lonestar. W.D. Von Gonten & Co.'s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and W.D. Von Gonten & Co. has not performed other work for us or our affiliates that would affect its objectivity. The engineering information presented in W.D. Von Gonten & Co.'s reports was overseen by William D. Von Gonten, Jr., P.E. Mr. Von Gonten is an experienced reservoir engineer having been a practicing petroleum engineer since 1990. He has a Bachelor of Science degree in Petroleum Engineering from Texas A&M University and is a licensed Professional Engineer in the State of Texas.

Technology Used To Establish Proved Reserves

Our independent reserve engineers follow SEC rules and definitions in preparing their reserve estimates. Under SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geological, geochemical 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. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our reserves include electrical logs, radioactivity logs, core analysis, geologic maps and available downhole and production data, seismic data and well-test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

Internal Controls Over Reserves Estimation Process

Our estimated reserves at December 31, 2018 and 2017 were prepared by W.D. Von Gonten & Co., independent reserve engineers. We expect to continue to have our reserve estimates prepared annually by our independent reserve engineers. Our internal professional staff works closely with W.D. Von Gonten & Co. to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the production, expense and well-ownership information, maintained in our reserve engineering database, is provided to our independent engineers. In addition, we provide such engineers other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures, pricing differentials and relevant economic criteria, including lease operating statements. We make all requested information, as well as our pertinent personnel, available to our independent engineers in connection with their evaluation of our reserves. Year-end reserve estimates are reviewed by our Vice President-Reservoir Engineering, our Chief Executive Officer and other senior management, and revisions are communicated to our board of directors.

Oil and Natural Gas Production Prices and Costs

Production, Revenues and Price History

The following table sets forth information regarding net production of oil, NGLs and natural gas and certain price and cost information attributable to our properties, for the years ended December 31, 2018 and 2017:

	Year ended December 31, 2018	Year ended December 31, 2017
Production		
Oil (Bbls/day):		
Western	2,290	1,873
Central	4,300	2,104
Eastern	215	351
Total Eagle Ford	6,805	4,328
NGLs (Bbls/day)		
Western	1,745	739
Central	415	166
Eastern	79	164
Total Eagle Ford	2,239	1,069
Natural Gas (Mcf/day)		
Western	10,430	5,046
Central	1,860	749
Eastern	375	793
Total Eagle Ford	12,665	6,588
Average daily production (BOE/d)	11,155	6,495
Average realized prices		
Oil ($/Bbl)	$ 67.53	$ 50.96
NGLs ($/Bbl)	22.60	18.48
Natural Gas ($/Mcf)	3.24	2.73
Operating expenses per BOE		
Lease operating and gas gathering	$ 6.39	$ 7.34
Production and ad valorem taxes	2.71	2.33
Depreciation, depletion and amortization	20.53	24.03

Drilling Activity

The following table sets forth our operated and non-operated drilling activity for the years ended December 31, 2018 and 2017. In the table, "gross" refers to the total wells in which we have a working interest and "net" refers to gross wells multiplied by our working interest therein.

	Year ended December 31,			
	2018		2017	
	Gross	Net	Gross	Net
Development Wells:				
Productive	18.0	15.3	12.0	11.3
Dry	—	—	—	—
Exploratory Wells:				
Productive	3.0	3.0	—	—
Dry	—	—	—	—
Total Wells:				
Productive	21.0	18.3	12.0	11.3
Dry	—	—	—	—

As of December 31, 2018, we were in process of drilling 3 gross (3.0 net) wells that are not included in the table above.

Acreage Data

The following table sets forth information relating to our leasehold acreage in the Eagle Ford. As of December 31, 2018, approximately 86% of our net Eagle Ford acreage was held by production.

	As of December 31, 2018					
	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Western Region	5,200	4,839	10,828	9,501	16,028	14,340
Central Region	15,551	11,817	34,843	24,013	50,394	35,830
Eastern Region	1,393	776	10,378	6,545	11,771	7,321
Total Eagle Ford	22,144	17,432	56,049	40,059	78,193	57,491

As of December 31, 2018, we had leases across the Eagle Ford representing 1,023 net acres expiring in 2019, 638 net acres expiring in 2020 and 1,021 net acres expiring in 2021 and beyond. We anticipate that our current and future drilling plans, together with selected lease extensions, will address a significant portion of our leases expiring in the Eagle Ford in 2019.

Operations

General

We operate 85% of the Eagle Ford wells in which we have a working interest and intend to maintain a high degree of operational control over substantially all of our producing locations. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors, engaged by us, provide all of the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

For the year ended December 31, 2018, purchases by our largest five customers accounted for 27%, 16%, 15%, 15% and 11% of our total revenues.

Since the oil and natural gas that we sell are commodities for which there are a large number of potential buyers, and because of the adequacy of the infrastructure to transport oil and natural gas in the areas in which we operate, if we were to lose one or more customers, we believe that we could readily procure substitute or additional customers such that our production volumes would not be materially affected for any significant period of time.

Transportation

During the initial development of our fields, we consider all gathering and delivery infrastructure options in the area of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The oil is then transported by the purchaser by truck to a tank farm or by pipeline. Our natural gas is generally transported from the wellhead to the purchaser's pipeline interconnection point through our gathering system.

Competition

We operate in a highly competitive environment for leasing and acquiring properties and in securing trained personnel. Our competitors include major and independent oil and natural gas companies that operate in our project areas. These competitors include, but are not limited to, Chesapeake Energy Corporation, EP Energy Corporation, EOG Resources, Inc., Carrizo Oil & Gas, Inc., Marathon Oil Corporation, Sanchez Energy Corporation, SilverBow Resources, Inc. and Stonegate Production Company. Many of our competitors have substantially greater financial, technical and personnel resources than we do, which can be particularly important in the areas in which we operate. As a result, our competitors may be able to pay more for productive crude oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry. We are also affected by the competition for and the availability of equipment, including drilling rigs and completion equipment. We are unable to predict when, or if, shortages of such equipment may occur or how they would affect our development and exploitation programs.

Seasonality of Business

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months, resulting in seasonal fluctuations in the price we receive for our natural gas production. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain an additional title opinion or conduct a review to ensure all title is current relative to previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties. After an acquisition, we review the assignments from the seller for scrivener's and other errors and execute and record corrective assignments as necessary.

We typically conduct title review of all acquired properties, regardless of whether they have proved reserves. Prior to the commencement of drilling operations on any property, we update our title examination and perform curative work with respect to significant defects or customary assignments, if any. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

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

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any well drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties predominately range from 19.0% to 25.0% resulting in a net revenue interest to us ranging from 75.0% to 81.0%.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, crude oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for crude oil and natural gas production have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Failure to comply with applicable laws and regulations can result in substantial penalties. Furthermore, such laws and regulations are frequently amended or reinterpreted, and new proposals that affect the crude oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We believe that we are in substantial compliance with all applicable laws and regulations and that our continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. Nor are we currently aware of any specific pending legislation or regulation that is reasonably likely to be enacted, or for which we cannot predict the likelihood of enactment, and that is reasonably likely to have a material effect on our financial position, cash flows or results of operations.

Regulation of Sales and Transportation of Oil

Our sales of oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by FERC pursuant to the Interstate Commerce Act of 1887 ("ICA"), the Energy Policy Act of 1992 ("EPAct"), and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport oil and refined products (collectively referred to as "petroleum pipelines"), be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC. EPAct deemed certain interstate petroleum pipeline rates then in effect to be just and reasonable under the ICA, which are commonly referred to as "grandfathered rates." Pursuant to EPAct, FERC also adopted a generally applicable rate-making methodology, which, as currently in effect, allows petroleum pipelines to change their rates provided they do not exceed prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods ("PPI"), plus 1.3%. For the five-year period beginning July 1, 2016, the index will be PPI plus 1.23%.

FERC has also established cost-of-service rate-making, market-based rates and settlement rates as alternatives to the indexing approach. A pipeline may file rates based on its cost of service if there is a substantial divergence between its actual costs of providing service and the rate resulting from application of the index. A pipeline may charge market-based rates if it establishes that it lacks significant market power in the affected markets. Further, a pipeline may establish rates through settlement with all current non-affiliated shippers.

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

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could re-enact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in the adoption of the Natural Gas Wellhead Decontrol Act, which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas, transportation rates and terms and conditions of service, which affect the marketing of natural gas that we produce as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others that buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

Gathering services, which occur upstream of jurisdictional transmission services, are regulated by the states onshore and in state waters. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities is done on a case-by-case basis. To the extent that FERC issues an order that reclassifies transmission facilities as gathering facilities and, depending on the scope of that decision, our costs of getting gas to point of sale locations may increase. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, non-discriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services vary from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Environmental and Occupational Safety and Health Matters

Our exploration, development, production and processing operations are subject to various federal, state and local laws and regulations relating to health and safety, the discharge of materials into the environment and environmental protection. These laws and regulations may, among other things: require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and natural gas drilling and production; restrict the way we handle or dispose of our wastes; limit or prohibit construction or drilling activities in sensitive areas, such as wetlands, wilderness areas, or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

These laws and regulations may also restrict the rate of crude oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the crude oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. In addition, Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly emissions control, waste handling, disposal, clean-up and remediation requirements for the crude oil and gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretations of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position in the future. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. While we believe that we are in substantial compliance with existing environmental laws and regulations and that current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that this will continue in the future.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse effect on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

The federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. CERCLA exempts "petroleum, including oil or any fraction thereof" from the definition of "hazardous substance" unless specifically listed or designated under CERCLA. While the EPA interprets CERCLA to exclude oil and fractions of oil, hazardous substances that are added to petroleum or that increase in concentration as a result of contamination of the petroleum during use are not considered part of the petroleum and are regulated under CERCLA as a hazardous substance.

Potentially responsible parties under CERCLA include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "potentially responsible parties" may be subject to strict, joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also generate solid and hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. The RCRA imposes requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations we generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes. The RCRA regulations specifically exclude from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil, natural gas or geothermal energy. Following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 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, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 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 the 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. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs and drilling operations to manage and dispose of generated wastes and a corresponding decrease in their drilling operations, which developments could have a material adverse effect on our business. In addition, Legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and cleanup requirements. No such effort has been successful to date.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce crude oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including groundwater contaminated by prior owners or operators) and to perform remedial operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act, as amended, or the Clean Water Act ("CWA"), and analogous state laws impose restrictions and controls regarding the discharge of pollutants into waters of the United States. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the United States. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permits issued by the EPA or analogous state agencies. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure 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 CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Currently, storm water discharges from crude oil and natural gas exploration, production, processing or treatment operations, or transmission facilities are exempt from regulation under the CWA.

In May 2015, the EPA issued final rules attempting to clarify the federal jurisdictional reach over waters of the United States but this rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals as that appellate court and several other district courts ponder lawsuits opposing implementation of the rule. In January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction rests with the federal district or appellate courts. On March 6, 2017, the U.S. Department of Justice filed a motion with the U.S. Supreme Court requesting the Court to stay the suit regarding which courts should hear challenges to this rule. In November 2017, the EPA and the Army Corps of Engineers issued a notice to rescind the Clean Water Rule and re-codify the regulatory text that existed prior to 2015 defining "water of the United States." On January 22, 2018, the U.S. Supreme Court unanimously held that challenges to the 2015 rules could only be raised in federal district courts and remanded the case back to U.S. District Courts. The EPA and the Army Corps of Engineers then issued a stay of the rule's effective date until February 6, 2020 and the U.S. District Court for North Dakota, issued a stay that remains in effect. In December 2018, the EPA and the Army Corps of Engineers proposed changes to the rule that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intentions to challenge the proposed replacement rule. Litigation is ongoing challenging the actions of the EPA and the Army Corps of Engineers and at this time, it is unclear what impact these actions will have on the implementation of the rules. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as other enforcement mechanisms for noncompliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Air Emissions

The Clean Air Act, as amended ("CAA"), and comparable state laws and regulations restrict the emission of air pollutants from many sources, including oil and natural gas operations, and impose various monitoring and reporting requirements. These laws and regulations may require us to obtain preapproval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. For example, the EPA also issued CAA regulations relevant to hydraulic fracturing in 2012, including a new source performance standard for volatile organic chemicals ("VOCs") and sulfur dioxide ("SO2") emissions with expanded applicability to natural gas operations, as well as a new air toxics standard. These rules create significant new technology requirements for controlling wellhead emissions from our operations. The EPA has made several changes to these rules in response to industry and environmental group legal challenges and administrative petitions, including, most recently, a decision to include a specific performance standard for methane in the rules (discussed further below). In general, there is increasing interest in and focus on regulation of methane emissions from oil and natural gas operations, and hydraulic fracturing operations in particular, under the CAA.

In June 2016, the EPA published final rules establishing new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA's final rules include the NSPS at Subpart OOOOa to limit methane emissions from equipment and processes across the oil and natural gas source category. The rules also extend limitations on VOC emissions to sources that were unregulated under the previous NSPS at Subpart OOOO. Affected methane and VOC sources include hydraulically fractured (or re-fractured) oil and natural gas well completions, fugitive emissions from well sites and compressors, and pneumatic pumps. Several states and industry groups have filed suit before the D.C. Circuit challenging EPA's implementation of the methane rule and legal authority to issue the methane rules. On June 12, 2017, EPA proposed a two year stay of the fugitive emissions, pneumatic pump and professional engineer certification requirements in the methane rule while the agency reconsiders the rule. In September 2018, the EPA proposed further amendments that would reduce the 2016 Subpart OOOOa standards' fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 Subpart OOOOa standards and the EPA's attempts to delay the implementation of the rule. In May 2016, the EPA also announced its intention to impose methane emission standards for existing sources, and in February 2018, new standards for methane emission from oil and gas wells were proposed by the Trump Administration, currently subject to a 60-day comment period. The EPA also finalized separate rules under the CAA in June 2016 regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities (such as tank batteries and compressor stations), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In addition, in October 2015, the EPA issued a final rule under the CAA, lowering the NAAQS for ground-level ozone from the current standard of 75 ppb for the current 8-hour primary and secondary ozone standards to 70 ppb for both standards. The final rule became effective on December 28, 2015 and was challenged in courts. The D.C. Circuit struck down parts of the rule in February 2018. In April 2018 and July 2018, the EPA issued area designations for all areas not addressed in the previous rule. States with moderate or high nonattainment areas must submit state implementation plans to EPA by October 2021. States are expected to implement more stringent permitting and pollution control requirements as a result of the final rule, which could apply to our operations.

We cannot predict future regulatory requirements in this area or the cost to comply with such requirements. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas we produce. We further note that states are authorized to regulate methane emissions within their boundaries provided their requirements are not weaker than federal rules.

Regulation of GHG Emissions

Climate and related energy policy, laws and regulations could change quickly, and substantial uncertainty exists about the nature of many potential developments that could impact the sources and uses of energy. In December 2015, the United States and 194 other countries, adopted the Paris Agreement, committing to work towards limiting global warming and agreeing to a monitoring and review process of GHG emissions. This will heighten political pressure on the United States to ensure continued compliance with enforcement measures resulting from the Clean Air Act and to bring forward further actions to reduce GHGs in the period post 2030. On October 4, 2016, the E.U. ratified the Paris Agreement, thus meeting the threshold for the agreement to come into force. On June 1, 2017, President Trump announced that the United States planned to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework 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 is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The EPA requires the reporting of GHGs from specified large GHG emission sources, including GHGs from petroleum and natural gas systems that emit more than 25,000 tons of GHGs per year. Reporting is required from onshore and offshore petroleum and natural gas production, natural gas processing, transmission and distribution, underground natural gas storage and liquefied natural gas import, export and storage. While new legislation requiring GHG controls is not expected at the national level in the near term, almost one-half of the states have taken actions to monitor and/or reduce emissions of GHGs, including obligations on utilities to purchase renewable energy and GHG cap and trade programs. Although most of the state level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future.

Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources, such as coal, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources, such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, 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, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas we produce or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Hydraulic Fracturing Activities

The federal Safe Drinking Water Act ("SDWA") and comparable state statutes may restrict the disposal, treatment or release of water produced or used during crude oil and natural gas development. Subsurface emplacement of fluids (including disposal wells) is governed by federal or state regulatory authorities that, in some cases, include the state oil and gas regulatory authority or the state's environmental authority. We utilize hydraulic fracturing in our operations as a means of maximizing the productivity of our wells and operate saltwater disposal wells to dispose of produced water. The federal Energy Policy Act of 2005 amended the Underground Injection Control ("UIC") provisions of the SDWA to expressly exclude hydraulic fracturing without diesel additives from the definition of "underground injection." However, the U.S. Senate and House of Representatives have considered several bills in recent years to end this exemption, as well as other exemptions for crude oil and gas activities under U.S. environmental laws.

Federal agencies have also begun to directly regulate hydraulic fracturing. The EPA has asserted federal regulatory authority over, and issued permitting guidance for, hydraulic fracturing involving diesel additives under the SDWA's UIC Program. As a result, service providers or companies that use diesel products in the hydraulic fracturing process are expected to be subject to additional permitting requirements or enforcement actions under the SDWA. The EPA has also issued CAA regulations relevant to hydraulic fracturing in 2012, including the NSPS for VOC and SO2 emissions with expanded applicability to natural gas operations and new national emission standards for hazardous air pollutants standards for air toxics (although the Trump Administration has indicated an intent to review this rule). Also, in June 2016, the EPA finalized rules to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. These regulatory developments are indicative of increasing federal regulatory activity related to hydraulic fracturing, which has the potential to create additional permitting, technology, recordkeeping and site study requirements, among others, for our business. In addition, federal agencies have started to assert regulatory authority over the process. 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. The U.S. Bureau of Land Management (the "BLM") had developed comprehensive regulations for hydraulic fracturing on federal land in 2015 subject to extensive litigation challenges and in December 2017, the BLM filed notice that it was withdrawing the rules. The State of California and environmental groups filed a lawsuit against BLM seeking to enforce the rules and such litigation is ongoing.

State governments in the areas where we operate have adopted or are considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Such measures may address any risk to drinking water, the potential for hydrocarbon migration and disclosure of the chemicals used in fracturing. A majority of states around the country, including Texas, have also adopted some form of fracturing fluid disclosure law to compel disclosure of fracturing fluid ingredients and additives that are not subject to trade secret protection. Other states, such as Ohio and Texas, have begun to study potential seismic risks related to underground injection of fracturing fluids. For example, on October 28, 2014, the Texas Railroad Commission, or TRC, published a new rule governing permitting or re-permitting of disposal wells that would require, 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 permit fails to demonstrate that the saltwater or other 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.

Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions of our operations.

At this time, it is not possible to estimate the potential impact on our business of these state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

ESA and Migratory Birds

The federal Endangered Species Act, as amended ("ESA"), restricts activities that may affect endangered and threatened species or their habitats. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the Agency's 2017 fiscal year. The U.S. Fish and Wildlife Service did not meet that deadline, but continues to consider the listing of additional species under the ESA. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. While some of our facilities may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA and the Migratory Bird Treaty Act. However, the designation of previously unidentified endangered or threatened species or habitats in areas where our operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could have a material adverse impact on the value of our leases.

National Environmental Policy Act

Our operations on federal lands are subject to the National Environmental Policy Act, or NEPA. Under NEPA, federal agencies, including the Department of the Interior must evaluate major agency actions having the potential to significantly impact the environment. This review can entail a detailed evaluation including an Environmental Impact Statement. This process can result in significant delays and may result in additional limitations and costs associated with projects on federal lands.

OSHA

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended (the "OSH Act"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSH Act's hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act, and comparable state statutes require that information be maintained concerning hazardous materials used, produced or released in our operations and that this information be provided to employees, state and local government authorities and citizens. In March 2016, OSHA amended its legal requirements, publishing a final rule that established a more stringent permissible exposure limit for exposure to respirable crystalline silica and provided other provisions to protect employees, such as requirements for exposure assessment, methods for controlling exposure, respiratory protection, medical surveillance, hazard communication, and recordkeeping. This final rule became effective in June 2016. However, several industry groups have filed suit in the D.C. Circuit to halt implementation of the rule. Increasing concerns about worker safety at drill sites may lead to increased regulation and enforcement or related tort claims by our employees. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Related Permits and Authorizations

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

We have not experienced any material adverse effect from compliance with environmental requirements; however, there is no assurance that this will continue. We did not have any material capital or other nonrecurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2018, nor do we anticipate that such expenditures will be material in 2019.

Related Insurance

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

Employees

As of December 31, 2018, we had 74 employees, including 10 engineers and geoscientists, 10 land professionals and 30 field operating personnel. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

We also contract for the services of independent consultants involved in land, engineering, regulatory, accounting, financial and other disciplines as needed.

Recent Events

Issuance of 11.25% Senior Notes

In January 2018, we issued $250.0 million of 11.250% senior notes due 2023 to U.S.-based institutional investors. The net proceeds of $244.4 million were used to fully retire the 8.750% Senior Notes due 2018, which included principal, interest and prepayment premium totaling approximately $162.0 million. The remaining net proceeds were used to reduce borrowings under our Credit Facility.

Sooner Acquisition

On November 15, 2018, we completed the acquisition of producing properties in the Sugarkane Field in DeWitt County, Texas, for $38.7 million, before closing adjustments, from Sabine Oil & Gas Corporation and Alerion Gas AXA, LLC (the "Sooner Acquisition"). The acquisition was financed with funds available from our Credit Facility, as well as cash from operations. The acquisition, which is 95% operated, included approximately 3,071 gross acres (2,693 net acres) and approximately 800 BOE/d of production from 20 producing wells on the date of the acquisition.

Item 1A. Risk Factors.

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

Oil, natural gas and NGL prices are volatile. A substantial or extended decline in the price of these commodities may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our revenues, profitability, liquidity, ability to access capital and future growth prospects are highly dependent on the prices we receive for our oil, natural gas and NGLs. The prices of these commodities are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and NGLs have been volatile, and this volatility may continue in the future. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide and regional economic and political conditions;
- the domestic and global supply of, and demand for, oil, natural gas and NGLs;
- the cost of exploring for, developing, producing and marketing oil, natural gas and NGLs;
- the proximity, capacity, cost and availability of oil, natural gas and NGL pipelines and other transportation facilities;
- the price and quantity of imports of foreign oil, natural gas and NGLs;
- the level of global oil, natural gas and NGL exploration and production;
- the level of global oil, natural gas and NGL inventories;
- weather conditions and natural disasters;
- domestic and foreign governmental laws, regulations and taxes;
- volatile trading patterns in commodities futures markets;
- price and availability of competitors' supplies of oil, natural gas and NGLs;
- the actions of the Organization of Petroleum Exporting Countries ("OPEC") and the ability of OPEC and other producing nations to agree to and maintain production levels;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Further, oil, natural gas and NGL prices do not necessarily fluctuate in direct relationship to each other. Because approximately 57% of our estimated proved reserves as of December 31, 2018 were attributed to oil, our financial results are more sensitive to movements in oil prices.

As of December 31, 2018, we had in place hedges covering approximately 6,000 Bbls/d for 2019 at an average price of approximately $53.88 per Bbl. To the extent we are unhedged, we have significant exposure to adverse changes in the prices of oil and natural gas that could materially and adversely affect our business and results of operations.

WTI oil prices have declined from over $100 per Bbl in September 2014 to $45.41 per Bbl at December 31, 2018. Such a decline in oil price, if sustained, will have a material impact on our annual revenues and has caused us to take actions to reduce the costs of drilling and our operations.

Prolonged further sustained declines in oil, natural gas or NGL prices may act to reduce our cash flows further and adversely affect our financial condition. In the event of further sustained declines, our liquidity could be reduced, our access to equity or long-term debt might be restricted, and our ability to meet our capital expenditure obligations and financial commitments might be adversely affected. We may choose to defer drilling activity and/or production from existing wells for a number of reasons, including the following:

- drilling activity is sanctioned on the expectation of matching the drilling budget with operating cash flows and securing reasonable rates of returns based on the then prevailing oil, natural gas and NGL prices; if those prices decline and operating cash flows are reduced, there is a risk that drilling may be curtailed or postponed; and

- operating costs on our Eagle Ford properties are so low that production from these properties would likely continue to contribute to cash flows, but we may choose to defer production in the event that we consider there may be greater value in producing later.

Furthermore, prolonged sustained further declines in oil, natural gas or NGL prices may reduce the amount of oil, natural gas and NGLs we can produce economically and negatively impact the value of our estimated oil, natural gas and NGL reserves, the carrying value of our oil, natural gas and NGL reserves, the PV-10 valuations of our oil, natural gas and NGL reserves, and the Standardized Measure relating to oil, natural gas and NGL reserves.

Our future cash flows and results of operations are highly dependent on our ability to find, develop or acquire additional oil and natural gas resources.

Our business strategy is to generate profit through the acquisition, exploration, development and production of crude oil and natural gas reserves. Our future success therefore depends on our ability to find, develop or acquire additional crude oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves or both. We may not be able to find, develop or acquire additional reserves on an economically viable basis. Furthermore, if crude oil and natural gas prices increase, the cost of finding, developing or acquiring additional reserves could also increase.

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

Exploration and development activities involve numerous risks beyond our control, including the risk that no commercially productive oil or natural gas reservoirs will be discovered and that drilling will not result in commercially viable oil or natural gas production. In addition, the future cost and timing of drilling, completing and operating wells is often uncertain. Drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- lack of prospective acreage available on acceptable terms;

- unexpected or adverse drilling conditions;

- elevated pressure or irregularities in geologic formations;

- equipment failures or accidents;

- adverse weather conditions;

- title problems;

- limited availability of financing upon acceptable terms;

- limitations in the market for oil, gas and NGLs;
- reductions in oil, NGLs and natural gas prices;
- compliance with governmental requirements, laws and regulations; and
- shortages or delays in the availability of drilling rigs, equipment and personnel.

Even if our exploitation, development and drilling efforts are successful, our wells, once completed, may not produce reserves of crude oil, NGLs or natural gas that are economically viable or that meet our prior estimates of economically recoverable reserves. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially impact our operations and financial position by reducing our available cash and liquidity. In addition, the potential for production decline rates for our wells could be greater than we expect. Because of the risks and uncertainties inherent to our businesses, our future drilling results may not be comparable to our historical results.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves with resulting adverse effects on our cash flow and liquidity.

The oil and natural gas industry is capital intensive. We currently make, and expect to continue to make, substantial capital expenditures for the acquisition, development and exploration of oil, natural gas and NGL reserves. We currently expect to allocate between $107 million and $130 million under our 2019 capital program to drilling and completing approximately 17-20 gross wells across our properties in the Eagle Ford.

The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, crude oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

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

- our proved reserves;
- the amount of crude oil, natural gas and NGLs we are able to produce from existing wells;
- the prices at which our crude oil, natural gas and NGLs are sold;
- the costs at which our crude oil, natural gas and NGLs are extracted;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital; and
- our ability to acquire, locate and produce new reserves and the cost of such reserves.

If our revenues or the borrowing base under the Credit Facility decreases as a result of lower crude oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under the Credit Facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition and results of operations.

Any significant reduction in our borrowing base under the Credit Facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

The Credit Facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually on May 1 and November 1 of each year. The borrowing base depends on, among other things, our lenders' evaluation of our oil and natural gas reserves. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the Credit Facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. Effective November 15, 2018, we received notification that the borrowing base for the Credit Facility was $275 million, which represents the November 2018 redetermination. Our next scheduled borrowing base redetermination is scheduled for May 1, 2019. Borrowing availability was $91.5 million as of December 31, 2018, which reflects $0.5 million of letters of credit outstanding.

In the future, we may not have access to adequate funding under the Credit Facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover any defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans or make required repayments under the Credit Facility, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities and substantial losses, which may not be fully covered by our insurance.

The oil and natural gas business involves significant operating hazards and risks such as:

- well blowouts;
- mechanical failures;
- fires and explosions;
- pipe or cement failures and casing collapses, which could release natural gas, oil, drilling fluids or hydraulic fracturing fluids;
- uncontrollable flows of oil, natural gas or well fluids;
- earthquakes and natural disasters;
- geologic formations with abnormal pressures;
- handling and disposal of materials, including drilling fluids and hydraulic fracturing fluids;
- pipeline ruptures or spills;
- releases of toxic gases; and
- other environmental hazards and risks.

Any of these hazards and risks can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and the property of others.

We maintain insurance against losses and liabilities in accordance with customary industry practices and in amounts that our management believes to be prudent. However, we are not insured against all operational risks and such coverage is not available to us. We do not carry business interruption insurance. We may elect not to carry insurance if our management believes that the cost of available insurance is excessive relative to the risks presented.

We could sustain significant losses and substantial liability for uninsured risks or in amounts in excess of existing insurance coverage. We cannot insure fully against pollution and environmental risks. We cannot assure investors that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Our planned exploratory drilling involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques, which are subject to risks. As a result, drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns.

Risks that we face while drilling include, but are not limited to:

- landing our well bore in the desired formation;
- staying in the desired formation while drilling horizontally through the formation;
- running our casing the entire length of the well bore; and
- being able to run tools and other equipment consistently through the well bore.

Risks that we face while completing our wells include, but are not limited to:

- being able to fracture and stimulate the planned number of stages;
- being able to run tools the entire length of the well bore during completion operations; and
- successfully cleaning out the well bore after completion of the final fracture stimulation stage.

The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history, and, consequently, it is more difficult to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling does not meet our anticipated results or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and limited takeaway capacity and/or declines in crude oil and natural gas prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments, we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review, and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs and crews;
- the availability of leases and permits on reasonable terms for the prospects; and
- reprioritization of drilling schedule based on the acquisition of new properties.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. Wells that are currently part of our capital plan may be based on statistical results of drilling activities in other 3-D project areas that we believe are geologically similar rather than on analysis of seismic or other data in the prospect area, in which case actual drilling and results are likely to vary, possibly materially, from those statistical results. In addition, our drilling schedule may vary from our expectations because of future uncertainties. In addition, our ability to produce oil and gas may be significantly affected by the availability and prices of hydraulic fracturing equipment and crews. There can be no assurance that these projects can be successfully developed or that any identified drill sites or budgeted wells will, if drilled, encounter reservoirs of commercially productive oil or gas. We may seek to sell or reduce all or a portion of our interest in a project area or with respect to prospects or budgeted wells within such project area.

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

SEC rules only permit, subject to limited exceptions, us to book our PUDs if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement limits our ability to book additional PUDs as we pursue our drilling program. Moreover, we may be required to write down our PUDs if we do not drill those wells within the required five-year time frame.

Our identified drilling locations are subject to many uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- the ongoing review and analysis of geologic and engineering data;
- the availability of sufficient capital resources to us and the other participants to drill and complete the prospects;
- the approval of the prospects by other participants once additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for crude oil, natural gas and NGLs and the availability and prices of drilling rigs and personnel;
- the ability to maintain, extend or renew leases and permits on reasonable terms for the prospects;
- additional due diligence;
- regulatory requirements and restrictions; and
- the opportunity to divert our drilling budget to preferred prospects on acquired acreage or to secure other acreage by farming in.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. Wells that are currently part of our capital plan may be based on results of drilling activities in other areas that we believe are geologically similar to a prospect rather than on analysis of seismic or other data in the prospect area, in which case actual drilling and results are likely to vary, possibly materially, from results in other areas. In addition, our drilling schedule may vary from our expectations because of future uncertainties. In addition, our ability to produce oil and natural gas may be significantly affected by the availability and prices of equipment and personnel.

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

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

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

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Our operations are concentrated in areas in which the oil and gas industry has historically increased rapidly, and as a result, demand for such drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities in these areas, and the costs for those items also increased. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, we may not be able to drill all of our acreage before our leases expire.

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

At December 31, 2018, approximately 71% of our total estimated proved reserves were classified as proved undeveloped reserves. Recovery of undeveloped reserves requires successful drilling and incurrence of significant capital expenditures. Our approximately 66.5 MMBOE of estimated proved undeveloped reserves will require an estimated $896.1 million of development capital over the next five years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. 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 require us to reclassify our proved undeveloped reserves as unproved reserves.

Further, our reserves data assumes that we can and will make these expenditures and that these operations will be conducted successfully. These assumptions, however, may not prove correct. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write them off. Any such write-offs of our reserves could reduce our ability to borrow and adversely affect our liquidity and available capital.

Our producing properties are located in the Eagle Ford Shale of South Texas, making us vulnerable to risks associated with operating in one geographic area.

All of our production during the year ended December 31, 2018 was derived from our properties in the Eagle Ford Shale region of South Texas. As a result of this geographic concentration, we may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of crude oil or natural gas. Additionally, we may be exposed to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in many or all of our wells within the Eagle Ford.

Approximately 71% of our net Eagle Ford Shale leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases and result in a material adverse effect on our crude oil, natural gas and NGLs reserves and future production and, therefore, our future cash flow and income.

As of December 31, 2018, approximately 71% of our net Eagle Ford leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil, natural gas and NGLs regardless of whether such acreage contains proved reserves. Unless production is established on the undeveloped acreage covered by our leases, such leases will expire. Our future crude oil, natural gas and NGLs reserves and production and, therefore, our future cash flow and income, are highly dependent on successfully developing our undeveloped leasehold acreage and holding on to such leases.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage or we timely exercise our contractual rights to extend the terms of such leases by continuous operations or the payment of lease extension payments or delay rentals.

Leases on oil and natural gas properties typically have a primary term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established, applicable lease extension payments or delay rentals are made, or such lease is otherwise maintained pursuant to any applicable continuous operations provision. If our leases or term assignments on our undeveloped properties expire and we are unable to renew the leases, we will lose our right to develop the related properties. The primary term of the leases for 1,023 net acres that is not currently held by production will expire at the end of 2019 if such leases are not extended. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and productions costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. If commodity prices remain low, we may be required to delay our drilling plans and, as a result, may lose our right to develop the related properties.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate and any significant inaccuracies in these reserve estimates or underlying assumptions could materially affect the actual quantities and present value of such reserves.

There are uncertainties inherent in estimating crude oil and natural gas reserves and their estimated value, including many factors beyond our control. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner and is based on assumptions that may vary considerably from actual results. Reservoir engineering also requires economic assumptions about matters such as crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Accordingly, actual production, crude oil and natural gas prices, revenues, taxes, operating expenses, expenditures and quantities of recoverable crude oil and natural gas reserves will likely vary, possibly materially, from estimates. Any significant variance in our estimates or the accuracy of our assumptions could materially affect the estimated quantities and present value of reserves.

We depend upon several significant customers for the sale of most of our crude oil, natural gas and NGL production. The loss of one or more of these customers could adversely affect our revenues in the short term.

For the year ended December 31, 2018, purchases by our largest five customers accounted for 84% of our total revenues. While we believe that we can procure substitute or additional customers to offset the loss of one or more of our current customers, there is no assurance that we would be successful in doing so on terms acceptable to us or at all. The loss of one or more of such customers could limit our access to suitable markets for the crude oil, natural gas and NGLs we produce. The availability of a ready market for any crude oil, natural gas and/or NGLs we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of crude oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of crude oil and natural gas production and federal regulation of crude oil, natural gas and NGLs sold in interstate commerce. We cannot assure you that we will continue to have ready access to suitable markets for our future crude oil, natural gas and NGL production.

Our hedging transactions expose us to counterparty credit risk.

Currently, all of our hedging arrangements are concentrated with three counterparties, each of which are lenders under the Credit Facility. If these counterparties fail to perform their obligations, we may suffer financial loss or be prevented from realizing the benefits of favorable price changes in the physical market for our crude oil, natural gas and NGLs.

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

The discounted future net cash flows is not necessarily the same as the current market value of our estimated crude oil and natural gas reserves. The current requirements for crude oil and natural gas reserve estimation and disclosures require the estimated discounted future net cash flows from proved reserves to be based on the average of the sales price on the first day of each month in the applicable year, with costs determined as of the date of the estimate. Actual future net cash flows also will be affected by various factors, including:

- the actual prices we receive for crude oil and natural gas;

- our actual operating costs in producing crude oil and natural gas;
- the amount and timing of actual production;
- supply and demand for crude oil and natural gas;
- increases or decreases in consumption of crude oil and natural gas; and
- changes in governmental laws and regulations or taxation.

In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

We have incurred losses from operations for various periods since our inception and may continue to do so in the future.

Although we had net income from operations for the year ended December 31, 2018, we incurred a net loss from operations of approximately $35.4 million for the year ended December 31, 2017. Our development of, and participation in, an increasingly larger number of prospects has required, and will continue to require, substantial capital expenditures. The uncertainty and factors described throughout this *Risk Factors* section may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to operate profitability and may not receive positive cash flows from operating activities in the future, which could adversely affect our business and the trading price of our Class A voting common stock.

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

Because crude oil and natural gas prices are subject to volatility, we may periodically enter into price-risk-management transactions such as fixed-rate swaps, costless collars, puts, calls and basis differential swaps to reduce our exposure to price declines associated with a portion of our oil and natural gas production and thereby achieve a more predictable cash flow. The use of these arrangements limits our ability to benefit from increases in the prices of crude oil and natural gas. Our derivative arrangements may apply to only a portion of our production, thereby providing only partial protection against declines in crude oil and natural gas prices.

These arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which production is less than expected, our customers fail to purchase contracted quantities of crude oil and natural gas or a sudden, unexpected event materially impacts crude oil or natural gas prices.

If crude oil and natural gas prices decrease, we may be required to write-down the carrying values of our crude oil and natural gas properties.

We review our proved crude oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our crude oil and natural gas properties, which may result in a decrease in the amount we can borrow under our Credit Facility. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our ability to borrow under our credit facility and adversely impact our results of operations and liquidity for the periods in which such charges are taken.

Our inability to market our crude oil and natural gas could adversely affect our business.

Market conditions or the unavailability of satisfactory crude oil and natural gas transportation arrangements may hinder our access to crude oil and natural gas markets or delay production. The availability of a ready market for our crude oil and natural gas production depends on a number of factors, including the demand for and supply of crude oil and natural gas and the proximity of reserves to pipelines and gathering 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 favorable terms could adversely impact our business and results of operations.

Our productive properties may be located in areas with limited or no access to pipelines, thereby requiring compression facilities or delivery by other means, such as trucking and train. Such restrictions on our ability to sell our crude oil or natural gas 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 period of time, possibly causing us to lose leases due to the lack of commercially established production.

We generally deliver our crude oil and natural gas production through gathering systems and pipelines that we do not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our crude oil and natural gas production may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system or for other reasons as dictated by the particular agreements. We may also enter into firm transportation arrangements for additional production in the future. Because we are obligated to pay fees on minimum volumes to our service providers under firm transportation agreements regardless of actual volume throughput, these firm transportation agreements may be significantly more costly than interruptible or short-term transportation agreements, which could adversely affect our business and results of operations.

A portion of our crude oil and natural gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, or field personnel issues or strikes. We may also voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted or curtailed, it could adversely affect our business and results of operations.

If we fail to establish and maintain proper internal controls, our ability to produce accurate financial statements or comply with applicable regulations could be impaired.

Under Section 404(a) of the Sarbanes-Oxley Act our management is required to assess and report annually on the effectiveness of our internal control over financial reporting and identify any material weaknesses in our internal control over financial reporting. Once we are no longer an emerging growth company, Section 404(b) of the Sarbanes-Oxley Act will require our independent registered public accounting firm to issue an annual report that addresses the effectiveness of our internal control over financial reporting.

Subsequent to December 31, 2018, our management identified a material weakness in the financial close process relating to calculation of basic and diluted earnings per share. As a result of this material weakness, management, under the supervision and with the participation of the Company’s Chief Executive Officer and Chief Accounting Officer, has concluded that the Company’s internal control over financial reporting and disclosure controls and procedures were not effective as of December 31, 2018.

As described in Part II, Item 9A of this Form 10-K, we are taking steps to remediate this material weakness. There can be no assurance that any measures we take will remediate the material weakness identified, nor can there be any assurance as to how quickly we will be able to remediate this material weakness.

If the Company’s remedial measures are insufficient to address this material weaknesses, or if further material weaknesses are discovered, the Company’s financial statements could contain additional errors which, in turn, could lead to errors in our financial reports and/or delays in our financial reporting, which could require us to further restate our operating results or cause our auditors to issue a qualified audit report.

In addition to the remediation measures we plan to take in response to our material weakness relating to earnings per share described in Part II, Item 9A of this Form 10-K, in order to establish effective disclosure controls and procedures and internal control over financial reporting, we will need to expend additional resources and provide additional management oversight. Implementing any appropriate changes to our internal controls may require specific compliance training of our directors and employees, entail substantial costs in order to modify our existing accounting systems, take a significant period of time to complete and divert management’s attention from other business concerns. These changes may not, however, ultimately be effective in allowing us to achieve and maintain adequate internal controls.

As a result of the material weakness described above, investors may lose confidence in our operating results, the price of our Class A common stock could decline and we may be subject to litigation or regulatory enforcement actions. In addition, if we are unable to meet the requirements of Section 404 of the Sarbanes-Oxley Act, we may not be able to remain listed on Nasdaq.

The terms of the Credit Facility may restrict our operations, particularly our ability to respond to changes or to take certain actions.

The Credit Facility contains a number of restrictive covenants that impose significant operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long-term best interest, including restrictions on our ability, subject to satisfaction of certain conditions, to:

- incur additional indebtedness and guarantee indebtedness;
- pay dividends or make other distributions or repurchase or redeem capital stock;
- prepay, redeem or repurchase certain debt;
- issue certain preferred stock or similar equity securities;
- make loans and investments;
- sell assets;
- incur liens;
- enter into transactions with affiliates;
- alter the businesses we conduct;
- enter into agreements restricting our subsidiaries' ability to pay dividends; and
- consolidate, amalgamate, merge or sell all or substantially all of our assets.

In addition, the restrictive covenants in the Credit Facility require us to maintain specified financial ratios and satisfy other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we may be unable to meet them.

A breach of the covenants or restrictions or under the Credit Facility could result in an event of default under the applicable indebtedness. Such a default may allow the creditors to accelerate the related debt and may result in the acceleration of any other debt to which a cross-acceleration or cross-default provision applies. In the event our lenders accelerate the repayment of our borrowings, we and our subsidiaries may not have sufficient assets to repay that indebtedness.

As a result of these restrictions contained in the Credit Facility, we may be limited in how we conduct our business, unable to raise additional debt or equity financing to operate during general economic or business downturns or unable to compete effectively or to take advantage of new business opportunities. These restrictions may further affect our ability to grow in accordance with our strategy. In addition, our financial results, our substantial indebtedness and our credit ratings could adversely affect the availability and terms of our current and future financing.

Our level of indebtedness may increase, reducing our financial flexibility.

We intend to fund our capital expenditures in 2019 through cash flow from operations and from borrowings under the Credit Facility and, if necessary, through debt or equity financings. Our ability to make the necessary capital investment to maintain or expand our asset base and develop oil and natural gas reserves will be impaired if cash flow from operations is reduced and external sources of capital become limited or unavailable. If we incur additional debt for these or other purposes, the related risks that we now face could intensify and we could face additional risks. Our level of debt could adversely affect our business and results of operations in several important ways, including the following:

- a portion of our cash flow from operations would be used to pay interest on borrowings;
- the covenants contained in our credit facilities limit our ability to borrow additional funds, pay dividends, dispose of assets or issue shares of preferred stock and otherwise may affect our flexibility in planning for, and reacting to, changes in general business and economic conditions;

- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;

- a leveraged financial position would make us more vulnerable to economic downturns and decreases in commodity prices and could limit our ability to withstand competitive pressures; and

- a debt that we incur under our credit facilities will be at variable rates, which could make us vulnerable to an increase in interest rates.

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

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including the Credit Facility and senior notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flow from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flow and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness which would have a material adverse effect on our business and operations.

Increased costs of capital could adversely affect our business.

Our business and operating results can be adversely affected by factors such as the availability, terms and cost of capital and increases in interest rates. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Disruptions in the global financial markets may lead to an increase in interest rates or a contraction in credit availability, which would impact our ability to finance our operations. We will require continued access to capital for the foreseeable future. A significant reduction in the availability of credit could materially and adversely affect our business, results of operations and financial condition.

The crude oil and natural gas industry is intensely competitive and many of our competitors have resources that are greater than ours.

The oil and natural gas industry is highly competitive. Public integrated and independent oil and gas companies, private equity backed and private operators are all active bidders for desirable crude oil and natural gas properties as well as the equipment and personnel required to operate those properties. Many of these companies have substantially greater financial resources, staff and facilities than we do. There is a risk that increased industry competition will adversely impact our ability to purchase assets or secure services at prices that will allow us to generate sufficient returns on investment in the future.

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

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

The loss of any of our key personnel could adversely affect our business, financial condition, the results of operations and future growth.

We are reliant on a number of key members of our executive management team, and we do not have employment agreements with any of them. Loss of such personnel may have an adverse effect on our performance. Certain areas in which we operate are highly competitive regions and competition for qualified personnel is intense. We may be unable to hire suitable field personnel for our technical team or there may be periods of time where a particular position remains vacant while a suitable replacement is identified and appointed. Our ability to manage our growth will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. We may not be successful in attracting and retaining the personnel required to grow and operate our business profitably.

Our ability to manage growth will have an impact on our business, financial condition and results of operations.

Our growth historically has been achieved through the acquisition of leaseholds and the expansion of our drilling programs. Future growth may place strains on our financial, technical, operational and administrative resources and cause us to rely more on project partners and independent contractors, potentially adversely affecting our financial position and results of operations. Our ability to grow will depend on a number of factors, including:

- our ability to obtain leases or options on properties;
- our ability to identify and acquire new exploratory prospects;
- our ability to develop existing prospects;
- our ability to continue to retain and attract skilled personnel;
- our ability to maintain or enter into new relationships with project partners and independent contractors;
- the results of our drilling programs;
- commodity prices; and
- our access to capital.

We may not be successful in upgrading our technical, operational and administrative resources or increasing our internal resources sufficiently to provide certain of the services currently provided by third parties, and we may not be able to maintain or enter into new relationships with project partners and independent contractors on financially attractive terms, if at all. If we are unable to achieve or manage growth, it may materially and adversely affect our business, results of operations and financial condition.

We may incur losses as a result of title deficiencies.

We may lose title to, or interests in, our leases and other properties if the conditions to which those interests are subject are not satisfied or if we do not have sufficient funds available to meet the commitments.

The existence of title differences with respect to our crude oil and natural gas properties could reduce their value or render such properties worthless, which would have a material adverse effect on our business and financial results. We do not obtain title insurance and have not obtained drilling title opinions on all of our crude oil and natural gas properties. As is customary in the industry in which we operate, we generally rely upon the judgment of crude oil and natural gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and before drilling a well on a leased tract, and we generally make title investigations and receive title opinions of local counsel before we commence drilling operations. In some cases, we perform curative work to correct deficiencies in the marketability or adequacy of the title assigned to us. In cases involving more serious title problems, the amount paid for affected crude oil and natural gas leases can be lost, and the target area can become undrillable. While we undertake to cure all title deficiencies prior to drilling, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease, our investment in the well and the right to produce all or a portion of the minerals under the property. A significant portion of our acreage is undeveloped leasehold, which has a greater risk of title defects than developed acreage.

Our operations are subject to health, safety and environmental laws and regulations that may expose us to significant costs and liabilities.

The conduct of exploring for, and producing oil, natural gas and NGLs may expose our personnel and other third parties to potentially dangerous working environments. Occupational health and safety legislation and regulations differ in each jurisdiction. If any of our employees suffer injury or death, compensation payments or fines may have to be paid, and such circumstances could result in the loss of a license or permit required to carry on the business, or other legislative sanction, all of which have the potential to materially and adversely affect our business, results of operations and financial condition.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of our wastes and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable, regardless of whether we were at fault, for the full cost of removing or remediating contamination, even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws. In addition, accidental spills or releases on our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition and results of operations. Aside from government agencies, the owners of properties where our wells are located, the operators of facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, as well as collect penalties for violations or obtain damages for any related personal injury or property damage. Some sites we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, emission, waste management or clean-up requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise materially and adversely affect our business, results of operations and financial condition. We may not be able to recover some or any of these costs from insurance.

In addition, our operations and financial performance may be adversely affected by governmental action, including delay, inaction, policy change or the introduction of new, or amendment of or changes in interpretation of existing legislation or regulations, particularly in relation to access to infrastructure, environmental regulation (including in respect of carbon emissions and management), royalties and production and exploration licensing. Federal and state regulators are increasingly targeting greenhouse gas emissions from oil and gas operations. While these regulatory efforts are evolving, they may require the installation of emission controls or mandate other action that may result in increased costs of operation, delay, uncertainty or exposure to liability.

Hydraulic fracturing has recently come under increased scrutiny and could be the subject of further regulation that could impact the timing and cost of development.

Hydraulic fracturing is an important and commonly used process in the completion of unconventional crude oil and natural gas wells. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into deep rock formations to stimulate crude oil or natural gas production. Currently, hydraulic fracturing is primarily regulated in the United States at the state level, which generally focuses on regulation of well design, pressure testing and other operating practices. However, some states and local jurisdictions across the United States, including states in which we operate, have begun adopting more restrictive regulation, including measures such as:

- required disclosure of chemicals used during the hydraulic fracturing process;
- restrictions on wastewater disposal activities;
- required baseline and post-drilling sampling of water supplies in close proximity to hydraulic fracturing operations;
- new municipal or state land use regulations, such as changes in setback requirements, which may restrict drilling locations or related activities;
- financial assurance requirements, such as the posting of bonds, to secure site restoration obligations; and
- local moratoria or even bans on crude oil and natural gas development utilizing hydraulic fracturing in some communities.

The Texas Railroad Commission recently adopted rules and regulations requiring that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well also must be disclosed to the public and filed with the Texas Railroad Commission. Any increased federal, state, local, foreign, or international regulation of hydraulic fracturing could reduce the volume of reserves that we can economically recover, which could materially and adversely affect our revenues and results of operations.

At the U.S. federal level, the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Also, in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. Further, the EPA finalized regulations under the CWA in June 2016 that prohibit wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands (which was challenged in a U.S. federal trial court, resulting in a decision in June 2016 against the rule, an appeal of that decision, and a U.S. federal appeals court ruling in September 2017 dismissing the appeals and vacating the trial court decision). The BLM rescinded the rule in December 2017.

There has been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts on surface water, and groundwater and, the potential for the disposal of produced water in underground formations to trigger earthquakes, and effects on the environment generally. A number of lawsuits and enforcement actions have been initiated across the country relating to hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

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

Under the Domenici-Barton Energy Policy Act of 2005 (“EP Act of 2005”), the Federal Energy Regulatory Commission (“FERC”) has civil penalty authority under the Natural Gas Act of 1938 (the “NGA”) and the Natural Gas Policy Act (“NGPA”) to impose penalties for current violations of up to $1,269,500 per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

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

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

Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Drilling activities require the use of water. For example, the hydraulic fracturing process that we employ to produce commercial quantities of oil and natural gas from many reservoirs, including in the Eagle Ford, requires the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities due to drought conditions. Water must be obtained from other sources and transported to the drilling site. The effects of climate change may further exacerbate water scarcity in certain regions. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce our reserves, which could have an adverse effect on our financial condition, results of operations and cash flows.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of crude oil and natural gas. In particular, regulatory focus on disposal of produced water and drilling waste through underground injection has increased because of alleged links between such injection and regional seismic impacts in disposal areas. For example, regulators in some states, including Texas, have responded to the potential concern that the injection of produced water (and other waste water from oil and gas operations) into underground disposal wells may trigger seismic activity.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, use and discharge of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could materially and adversely affect our business, results of operations and financial condition.

Climate change laws and regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In connection with the EPA finding that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act (“CAA”) that, among other things, require reduced GHG emissions from certain large stationary sources, and the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. In May 2016, the EPA released final regulations intended to reduce methane emissions from the oil and gas industry, including throughout the natural gas supply chain. The regulations could affect us indirectly by affecting our customer base or by directly regulating our operations. In either case, increased costs of operation and exposure to liability could result. However, on June 12, 2017, EPA proposed a two year stay of the fugitive emissions, pneumatic pump and professional engineer certification requirements in the methane rule while the agency reconsiders the rule. In September 2018, the EPA issued a proposed rulemaking that would reduce the 2016 standards’ fugitive emissions monitoring requirements and expand exceptions to controlling methane emissions from pneumatic pumps, among other changes. Various industry and environmental groups have separately challenged both the original 2016 standards and the EPA’s attempts to delay implementation of the rule. The EPA also finalized rules in 2016 that clarify when crude oil and natural gas sites should be aggregated for purposes of air permitting, which could increase our compliance and permitting costs.

In addition, Congress has considered legislation to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane that are understood to contribute to global warming. While comprehensive climate legislation will likely not be passed by either house of Congress in the near future, energy legislation and other initiatives continue to be proposed that may be relevant to greenhouse gas emissions issues. In December 2016, the United States was one of 175 countries to adopt the Paris Agreement at the 21st Conference of Parties, which requires member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. On October 4, 2016, the E.U. ratified the Paris Agreement, thus meeting the threshold for the agreement to come into force. On June 1, 2017, President Trump announced that the United States planned to withdraw from the Paris Agreement and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework 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 is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

Acts of terrorism (including eco-terrorism and cyber-attacks) could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and operations, and the assets and operations of our providers of gas gathering, processing, transportation and fractionation services, may be targets of terrorist activities (including eco-terrorist and cyber-terrorist activities) that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport, market or distribute natural gas, NGLs and oil. Acts of terrorism, as well as events occurring in response to or in connection with acts of terrorism, could cause environmental and other repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, acts of terrorism, and the threat of such acts, could result in volatility in the prices for natural gas, NGLs and oil and could affect the markets for such commodities.

Our business could be negatively impacted by security threats, including cyber-security threats, and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, 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. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, 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. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

Our ability to use our net operating loss carryforwards may be limited.

As of December 31, 2018, we had approximately $84.6 million of U.S. federal net operating loss carryforwards ("NOLs"). Our NOLs begin to expire in 2030. Utilization of these NOLs depends on many factors, including our future income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of taxable income that may be offset by NOLs when a corporation has undergone an "ownership change" (as determined under Section 382). Generally, a change of more than 50% in the ownership of a corporation's stock, by value, over a three-year period constitutes an ownership change for U.S. federal income tax purposes. Any unused annual limitation may be carried over to later years. We have previously experienced an ownership change and may experience more ownership changes in the future, which would result in an annual limitation under Section 382. The limitations arising from our prior ownership change or from any ownership change that may arise in the future may prevent utilization of our NOLs prior to their expiration. Future ownership changes or regulatory changes could further limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows if we attain profitability.

The recently passed comprehensive tax reform bill could adversely affect our business and financial condition.

On December 22, 2017, President Trump signed into law the Tax Cuts and Jobs Act (the "TCJA"), which significantly reforms the Internal Revenue Code. The TCJA, among other things, contains significant changes to corporate taxation, including a permanent reduction of the corporate income tax rate, a partial limitation on the deductibility of business interest expense, limitation of the deduction for certain NOLs to 80% of current year taxable income, an indefinite carryforward of certain NOLs, immediate deductions for certain new investments instead of deductions for depreciation expense over time and the modification or repeal of many business deductions and credits. The TCJA is complex and the Treasury Department and the Internal Revenue Service continue to release regulations relating to and interpretive guidance of the legislation contained in the TCJA. We continue to examine the impact of this tax reform legislation, and as its overall impact is uncertain, we note that the TCJA could adversely affect our business and financial condition. The impact of this tax reform legislation on holders of our common stock is also uncertain and could be adverse.

General economic conditions could adversely affect our business and future growth.

Instability in the global financial markets may have a material impact on our liquidity and financial condition, and we may ultimately face major challenges if conditions in the financial markets were to materially change or worsen. Our ability to access the capital markets or to borrow money may be restricted or may be more expensive at a time when we would need to raise capital, which could have an adverse effect on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. Such economic conditions could have an impact on our customers, causing them to fail to meet their obligations to us. In addition, such changes could have an impact on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments.

Also, market conditions could have an impact on our crude oil and natural gas derivative instruments if our counterparties are unable to perform their obligations or seek bankruptcy protection, which could lead to reductions in the demand for crude oil and natural gas, or reductions in the prices of oil and natural gas or both, which could have an adverse impact on our financial position, results of operations and cash flows. While the ultimate outcome and impact of changing economic conditions cannot be predicted, they may materially and adversely affect our business, results of operations and financial condition.

Changes in the differential between benchmark prices of crude oil and natural gas and the reference or regional index price used to price our actual crude oil and natural gas sales could have a material adverse effect on our results of operations and financial condition.

The reference or regional index prices that we use to price our crude oil and natural gas sales reflect a discount to the relevant benchmark prices. The difference between the benchmark price and the price we reference in our sales contracts is called a differential. We cannot accurately predict crude oil and natural gas differentials. Changes in differentials between the benchmark price for crude oil and natural gas and the reference or regional index price we reference in our sales contracts could materially and adversely affect our business, results of operations and financial condition.

Recent federal legislation could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our crude oil and natural gas production. Under the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”), the Commodity Futures Trading Commission (“CFTC”) issued regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are exempt from these limits. The position limits regulation was vacated by the United States District Court for the District of Columbia in September 2012. The CFTC has appealed the District Court’s decision and its Chairman has stated that the agency is working on developing a new proposed rulemaking to address position limits. The CFTC has finalized other regulations, including critical rulemakings on the “swap” and “swap dealer” definitions, swap dealer registration, swap data reporting and mandatory clearing, among others. The Dodd-Frank Act and CFTC rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. The legislation may also require the counterparties to our derivative contracts to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The new legislation and any new regulations could:

- significantly increase the cost of some derivative contracts (including through requirements to post collateral that could adversely affect our available liquidity);
- materially alter the terms of some derivative contracts;
- reduce the availability of some derivatives to protect against risks we encounter;
- reduce our ability to monetize or restructure our existing derivative contracts; and
- potentially increase our exposure to less creditworthy counterparties.

If we reduce our use of derivatives as a result of the new legislation 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 crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. If the new legislation and regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our financial condition and results of operations.

We may be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult.

In accordance with our business strategies, we periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future crude oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems may not be observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

Significant acquisitions and other strategic transactions may also involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

In addition, even if we successfully integrate an acquisition, it may not be possible to realize the full benefits we may expect, including with respect to estimated proved reserves, production volume or cost savings from operating synergies, within our expected time frame. Anticipated benefits of an acquisition may also be offset by operating losses relating to changes in commodity prices in crude oil and natural gas industry conditions, risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. Failure to realize the benefits we anticipate from an acquisition may materially and adversely affect our business, results of operations and financial condition.

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

Certain provisions in our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- requiring advance notice of stockholder intention to put forth director nominees or bring up other business at a stockholders' meeting;

- requiring the affirmative vote of 66 2/3% of the voting power of all then outstanding shares of Class A common stock entitled to vote in order for stockholders to adopt, amend or repeal any provision of our bylaws or certificate of incorporation; and

- providing that the number of directors shall be fixed from time to time by our board of directors pursuant to a resolution adopted by a majority of the total number of authorized directors (whether or not there exist any vacancies in previously authorized directorships) or by the stockholders. Newly created directorships resulting from any increase in our authorized number of directors will be filled only by a majority vote of our board of directors then in office, whether or not such directors number less than a quorum, and directors so chosen will serve for a term expiring at the annual meeting of stockholders at which the term of office to which they have been elected expires or until such director's successor shall have been duly elected and qualified.

In addition, we entered into a Board Representation Agreement ("Board Representation Agreement") with EF Realisation and securities purchase agreements with Chambers and Leucadia National Corporation pursuant to which these stockholders are each entitled to nominate a number of directors so long as certain ownership thresholds are maintained. Please read Note 14. Related Party Activities.

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

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

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Information regarding our oil and gas properties is included in Item 1. Business under *Overview - Our Eagle Ford Shale Properties, Non-Core Properties, Oil and Natural Gas Data, and Oil and Natural Gas Production Prices and Costs* above and in Note 3. *Acquisitions and Divestitures* of the Notes to our Consolidated Financial Statements included in Item 8.

In addition to the properties used in our operations, we own our corporate office building in Fort Worth, Texas, which we purchased in August 2017 for approximately $10 million.

Item 3. Legal Proceedings.

From time to time, we are party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial position or results of operations.

Item 4. Mine Safety Disclosures.

Not applicable.

Executive Officers and Directors

The following table provides information regarding the Company's executive officers and directors (ages are as of March 7, 2019):

Name	Position	Age
Frank D. Bracken, III	Chief Executive Officer and Director	55
Barry D. Schneider	Chief Operating Officer	56
Jason N. Werth	Chief Accounting Officer	43
Thomas H. Olle	Vice President - Reservoir Engineering	64
Jana Payne	Vice President - Geosciences	57
Gregory R. Packer	Vice President - General Counsel & Corporate Secretary	39
John Pinkerton	Chairman	65
Henry Ellis	Director	69
Daniel R. Lockwood	Director	61
Matthew B. Ockwood	Director	35
Stephen H. Oglesby	Director	69
Phillip Z. Pace	Director	55
Randy L. Wolsey	Director	69

Frank D. Bracken, III is our Chief Executive Officer. Mr. Bracken has served in this position since January 2012 and has served as a director and Chief Executive Officer of Lonestar Resources, Inc., our wholly-owned subsidiary, since January 2012. Mr. Bracken previously served as Senior Managing Director of Sunrise Securities from September 2008 to December 2011 and as Managing Director of Jefferies LLC from November 1999 to August 2008. During that time, Mr. Bracken led oil and natural gas transactions, spanning from public and private equity and debt offerings to joint ventures in the Haynesville Shale to one of the first purchases of a publicly-traded oil & gas company by a private equity firm. As Chief Financial Officer and a member of the board of directors at Gerrity Oil & Gas Corp, an NYSE-listed exploration and production company, Mr. Bracken was responsible for corporate budgeting and development, acquisitions, equity and debt financing in public and private offerings, and acquisitions and divestitures. Mr. Bracken holds a Bachelors of Arts degree from Yale University.

Barry D. Schneider is our Chief Operating Officer. Mr. Schneider has served in this position since May 2014. Prior to joining us, Mr. Schneider held the position of Vice President—Northern Region for Denbury Resources, Inc. from January 2012 to May 2014. Mr. Schneider was at Denbury for 15 years and held positions of increasing responsibility. After holding the positions of Vice President, Production & Operations, Mr. Schneider was promoted to Vice President-East Region in October 2009 and held that position until January 2012 when he became responsible for Denbury's Northern Region business unit. Prior to Denbury, Mr. Schneider was employed by Wiser Oil and Conoco-Philips. Mr. Schneider received his B.S. in Natural Gas Engineering from Texas A&M—Kingsville in 1985.

Jason N. Werth is our Chief Accounting Officer. Mr. Werth has served in this position since February 2018. Prior to joining us, Mr. Werth held the position of Director of Audit at Denbury Resources, Inc., where during his eight-year tenure he also served as SEC Reporting Manager and Assistant Controller of Corporate Accounting. Prior to Denbury, Mr. Werth was employed by Grande Energy and Orix Capital. Mr. Werth started his professional career in public accounting with Arthur Andersen LLP and later PricewaterhouseCoopers LLP, where he was an Assurance Manager. Mr. Werth holds Bachelor of Business Administration and Masters of Science degrees from Texas A&M University. He is a licensed Certified Public Accountant in the State of Texas.

Thomas H. Olle is our Vice President-Reservoir Engineering. Mr. Olle has served in this position since August 2010. Mr. Olle has over 35 years of oil and gas industry experience in multiple facets of the business, such as reservoir management and management of unconventional resource development projects including horizontal well field development and tertiary recovery projects. Mr. Olle also has significant experience with reserve evaluation and reporting, production engineering and operations, and business development functions including acquisitions, divestitures and new ventures. During his tenure at Encore Acquisition Company, Mr. Olle served as Vice President-Strategic Solutions and also held executive positions responsible for asset management and engineering. He also served as Senior Engineering Advisor for Burlington Resources from December 1985 to March 2002 and District Reservoir Engineer for Southland Royalty Company from May 1982 to December 1985. Mr. Olle holds a Bachelor's of Science in Mechanical Engineering with Highest Honors from the University of Texas in Austin.

Jana Payne was appointed our Vice-President of Geosciences in November 2015, bringing over 25 years of experience in the oil and gas industry. Prior to joining us, Ms. Payne held the position of Senior Exploitation Manager and Geologist at Halcon Resources, Inc. from November 2012 to May 2015. Ms. Payne spent eight years at Petrohawk Energy Inc. from June 2004 to October 2012 (and subsequently BHP Billiton following its acquisition of Petrohawk) as Geologic Manager and Senior Geologist, where her initial mapping of the Eagle Ford shale led to the discovery of the first commercial Eagle Ford Shale well and acquisition of over 300,000 acres by the Company. Ms. Payne's early career was as a geologist at Marathon Oil Co. and Petroleum Geo-Services, Inc. Ms. Payne has published works in learned journals and holds an MSc and BSc in geology from the University of Texas at Arlington.

Gregory R. Packer was appointed our Vice President, General Counsel & Corporate Secretary in October 2017. Prior to his appointment, Greg held the position of Senior Vice President, General Counsel & Corporate Secretary of Howard Energy Partners, a midstream company with operations in the Eagle Ford shale, Marcellus shale and Permian Basin. Before joining Howard Energy, Gregory practiced corporate and securities law at Latham & Watkins LLP, where he represented public and private companies and private equity sponsors in a wide range of transactions, including company formation, private and public mergers and acquisitions, as well as accessing equity and debt markets through private and public offerings, including initial public offerings. Mr. Packer is a graduate of the University of Chicago Law School, where he was a Lowenstein Scholar. Prior to attending law school, Mr. Packer obtained both Master's and Bachelor's degrees in accounting from Brigham Young University, where he was a G. Roger Victor Scholar.

John Pinkerton has served as a Director since August 2014 and became Chairman of the Board in August 2016. He was a director of Range Resources Corporation (NYSE: RRC) since 1989 and was Chairman of its Board of Directors from 2008 until January 2015. He joined Range as President in 1990 and served as Chief Executive Officer from 1992 until 2012. Prior to joining Range, Mr. Pinkerton served in various capacities at Snyder Oil Corporation for twelve years, including the position of Senior Vice President. Mr. Pinkerton received his Bachelor of Arts degree in Business Administration from Texas Christian University, where he now serves on the board of trustees, and a Master's degree from the University of Texas at Arlington. During his 27-year tenure Range Resources grew from its small cap origins to be a $13 billion dollar enterprise with a pre-eminent position in the Marcellus Shale. As CEO of Range Resources, Mr. Pinkerton established the technical expertise to enable a drilling-led strategy complemented by bolt-on acquisitions where synergies would enhance growth. This resulted in a rapid and impressive increase in the scale of the business, and seven consecutive years of double-digit growth in both production and reserves (adjusted for debt). Mr. Pinkerton has widespread skill in the management, acquisition and divestiture of oil and gas properties—including related corporate financing activities—hedging, risk analysis and the evaluation of drilling programs. He has represented the industry in policy matters, serving on the executive committee of America's Natural Gas Alliance. We believe that Mr. Pinkerton's experience at oil and natural gas exploration companies qualify him for service on our board of directors.

Henry B. Ellis has served as a director since October 2016. Mr. Ellis presently serves as managing director and Chief Executive Officer of Bassett California Co. and The Bassett Company. He previously served as a director of several other boards including Bluebonnet Savings Bank and State National Bank, and served as President of Mbank, El Paso and Chairman and CEO of Grayson County Bank. Mr. Ellis received his Bachelor of Arts degree in Business Administration from Texas Christian University. We believe that Mr. Ellis' financial experience in the banking industry qualifies him for service on our board of directors.

Daniel R. Lockwood has served as a director since May 2014. He also serves as Vice-President of New Tech Global and is responsible for overseeing and managing NTG engineering and project management services. Mr. Lockwood is a graduate of the Colorado School of Mines with a degree in Petroleum Engineering. Dan joined New Tech Engineering in 2000 and brings with him more than 35 years of engineering and management experience and is considered one of the industry's leading experts in Shale Operations. We believe that Mr. Lockwood's engineering and management experience in the oil and gas industry qualifies him for service on our board of directors.

Matthew B. Ockwood has served as a director since November 2017. Mr. Ockwood is a Managing Director of Chambers Energy Management, a Houston-based investment firm focused on providing flexible capital to the energy industry. While at Chambers Energy, Mr. Ockwood has led or participated in the execution of dozens of distinct oil and gas transactions ranging from secured debt to common equity. Prior to joining Chambers Energy, Mr. Ockwood was employed by Lehman Brothers where he worked in the Natural Resources investment banking group. Mr. Ockwood holds a B.B.A. in Finance, summa cum laude, and a Certificate in Leadership Study and Development from Texas A&M University. We believe that Mr. Ockwood's financial experience in the investment banking industry for a diverse set of energy clients qualifies him for service on our board of directors.

Stephen H. Oglesby has served as a director since March 2017. Before joining the Company, Mr. Oglesby served as Head of Energy, US Commercial Bank at Citibank, where he managed multiple offices and oversaw financial services provided to various private and public companies in the oil and gas industry, from December 2003 to January 2017. Mr. Oglesby previously served on the board of directors of various private companies, including Advanced Coiled Tubing, where he served as Chairman of its board of directors, Blackwell Plastics, and Goodman Manufacturing. Mr. Oglesby holds a Bachelor of Science in Accounting from Southern Illinois University. We believe that Mr. Oglesby is qualified to serve on our board of directors because of his extensive experience in financial services for diversified corporate and energy clients, and his background in finance and accounting.

Phillip Z. Pace has served as a director since June 2017. Mr. Pace is a Partner of Chambers Energy Management, a Houston-based investment firm focused on opportunistic credit investments in the energy industry. Mr. Pace has extensive experience in energy finance, including 19 years in oil and gas equity research. Mr. Pace joined Lehman Brothers in September 2008 after his retirement from Credit Suisse as Vice Chairman of the energy investment banking group. Mr. Pace received his Bachelor of Business Administration degree in Finance from Texas A&M University and has the Chartered Financial Analyst designation. We believe that Mr. Pace's financial experience in the investment banking industry for a diverse set of energy clients qualifies him for service on our board of directors.

Randy L. Wolsey has served as a director since January 2017. Mr. Wolsey is the founder and since February 2015 has been a co-owner of Lone Oak Minerals, a private company involved in the acquisition and selling of oil and gas minerals. Since January 2012, he has also been the owner of Solana, a private company involved in oil and gas and real estate investments. He is also the founder and since June 2006 has been a co-owner of Tanglewood Exploration, a private company involved in oil and gas exploration and production. He previously held management positions at companies including Glen Rose Oil & Gas and Justin Exploration. Mr. Wolsey received his Bachelor of Arts degree in Political Science from Midwestern State University. We believe that Mr. Wolsey's experience in the oil and gas industry qualifies him for service on our board of directors.

There are no family relationships among any of our directors or executive officers.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Dividend Policy

We currently intend to retain any earnings to fund the operation and expansion of our business and do not anticipate paying any cash dividends on our common stock for the foreseeable future. The declaration and payment of any dividends in the future by us will be subject to the sole discretion of our board of directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our operating subsidiaries, covenants associated with certain of our debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our board of directors. Moreover, if we determine to pay any dividend on common stock in the future, there can be no assurance that we will continue to pay such dividends. In addition, under our debt agreements, we are not permitted to pay cash dividends on our common stock without the prior written consent of the lenders.

Purchase of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes purchases of our Class A Common Stock during the fourth quarter of 2018:

	Total number of Shares Purchased	Average Price Paid per Share	Total Number of Shares that May Yet Be Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 2018	2,665	$ 9.15	—	—
November 2018	—	—	—	—
December 2018	—	—	—	—
Total	2,665		—	

Stock repurchases during the fourth quarter of 2018 were made in connection with delivery by our employees of shares to us to satisfy their tax withholding requirements related to the vesting of restricted shares.

Item 6. Selected Financial Data.

In thousands except shares and per share amounts and otherwise noted	Year Ended December 31, 2018	2017	2016
Consolidated Statements of Operations data:			
Oil and gas revenues	$ 201,169	$ 94,068	$ 57,972
Net income (loss)(1)(2)	19,348	(43,485)	(98,700)
Net income (loss) attributable to common stockholders	11,532	(47,453)	(98,700)
Net income (loss) attributable to common stockholders per share:(3)			
Basic	$ 0.29	$ (2.13)	$ (12.17)
Diluted	0.28	(2.13)	(12.17)
Weighted average number of common shares outstanding:			
Basic	24,619,730	22,252,149	8,106,931
Diluted	24,801,143	22,252,149	8,106,931
Consolidated Balance Sheets data (As of December 31)			
Total assets (4)	$ 744,112	$ 591,808	$ 448,217
Total long-term liabilities	461,544	324,162	255,901
Stockholder's equity	222,547	203,690	159,563
Consolidated Statements of Cash Flows data			
Cash provided by (used in)			
Operating activities	$ 88,072	$ 43,446	$ 24,269
Investing activities	(219,470)	(208,743)	(27,781)
Financing activities	134,215	161,767	5,258
Production (average daily)			
Oil (Bbls)	6,805	4,328	3,254
NGLs (Bbls)	2,239	1,069	1,166
Natural Gas (Mcf)	12,665	6,588	8,872
BOE (6:1)	11,155	6,495	5,899
Average unit sales prices, excluding impact of derivative settlements			
Oil	$ 67.53	$ 50.96	$ 39.43
NGLs	22.60	18.48	9.03
Natural gas	3.24	2.73	2.21
Costs per BOE			
Lease operating and gas gathering	$ 6.39	$ 7.34	$ 8.57
Production and ad valorem taxes	2.71	2.33	1.52
Depreciation, depletion and amortization	20.53	24.03	30.00
Proved oil and natural gas reserves			
Oil (MBbls)	53,499	50,701	24,288
NGLs (MBbls)	19,869	10,875	7,466
Natural gas (MMcf)	120,165	71,874	52,714
MBOE (6:1)	93,396	73,555	40,540

(1) Includes pre-tax impairments of assets of $12.2 million, $33.4 million and $33.9 for the years ended December 31, 2018, 2017 and 2016, respectively.

(2) Includes loss on extinguishment of debt of $8.6 million for the year ended December 31, 2018.

(3) Basic and diluted earnings per share are calculated using the two-class method. See Footnote 1. *Nature of Business and Presentation* in the Notes to Consolidated Financial Statements included in Item 8.

(4) During 2018, the Sooner acquisition added $38.5 million to oil and gas properties, and results from its operations were included beginning November 15, 2018. During 2017, the Battlecat and Marquis acquisitions added $109.8 million to oil and gas properties, and results from their operations were included beginning June 15 ,2017.

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements and Notes thereto included in Item 8, *Financial Statements and Supplementary Information*. Our discussion and analysis includes forward-looking information that involves risks and uncertainties and should be read in conjunction with *Risk Factors* under Item 1A of this Form 10-K, along with *Forward-Looking Information* at the end of this section for information on the risks and uncertainties that could cause our actual results to be materially different from our forward-looking statements.

Overview

Lonestar is an independent oil and natural gas exploration and production company focused on the exploration, development and production of unconventional oil, natural gas liquids and natural gas in the Eagle Ford Shale play in South Texas.

2018 Operational Highlights

During 2018, we achieved the following operating and financial results:

- Grew production by 72% year-over-year, averaging 11,155 BOE/d versus 6,495 BOE/d in 2017.
- Added a total of 19.8 MMBOE of proved reserves, which was equivalent to 487% of our 2018 production and represents a 27% increase from 2017.
- Drilled 21 (18.3 net) wells while utilizing a second rig for part of the year. Capital expenditures, excluding acquisitions, totaled $173.9 million.
- Purchased 3,071 gross (2,693 net) acres, including approximately 800 BOE/d of existing production, in the Sugarkane Field in DeWitt County, Texas for $38.7 million, prior to closing adjustments, which added approximately 11.3 MMBOE of proved reserves (see below).
- Improved our debt structure by issuing new $250MM 11.25% Senior Notes with a maturity date of 2023 and retired our 8.25% Senior Notes which were set to expire in 2019 (see below). We also increased our Credit Facility borrowing base from $160 million to $275 million over the course of the year and extended the maturity date to November 2023. The Credit Facility had over $91 million in availability as of year-end.

Changes in operating results between 2018 and 2017 were primarily driven by the following:

- Operating revenues increased by $107.1 million, or 114%, in 2018, primarily driven by a 72% increase in production and supported with a 24% increase in commodity prices. Net realized oil differentials improved by $3.14 per barrel from year to year.
- On a per-BOE basis, expenses improved significantly in 2018. Compared to 2017, lease operating and gas gathering expense decreased 13%, or $0.95 per BOE, general and administrative ("G&A") expense decreased 26%, or $1.40 per BOE, and interest expense decreased 13%, or $1.44 per BOE.
- Derivative financial instruments had a net gain of $22.7 million in 2018, compared to a net loss of $14.1 million in 2017, due to an increase in the non-cash fair value adjustments between the periods of $60.5 million, partially offset by $22.6 million of net cash paid for derivative settlements.

During 2018, we recognized net income attributable to common stockholders of $11.5 million, or $0.28 per diluted common share, compared to a net loss attributable to common stockholders of $47.5 million, or $2.13 per diluted common share, in 2017. Our 2018 net income includes a $12.2 million impairment charge on oil and gas properties and an $8.6 million loss on extinguishment of debt, while our 2017 net loss includes a $33.4 million impairment charge on oil and gas properties.

We generated $88.1 million of cash flow from operating activities during 2018, compared to $43.4 million during 2017, due primarily to a $107.1 million increase in production revenues.

Sooner Acquisition

In November 2018, we completed the acquisition of producing properties in the Eagle Ford shale play in DeWitt County, Texas, for $38.7 million, before closing adjustments, from Sabine Oil & Gas Corporation and Alerion Gas AXA, LLC (the "Sooner Acquisition"). The acquisition was financed with funds available from our Credit Facility, as well as cash from operations.

Issuance of 11.25% Senior Notes

In January 2018, we issued $250.0 million of 11.250% Senior Notes due 2023 (the "11.25% Senior Notes") to U.S.-based institutional investors. The net proceeds of $244.4 million were used to fully retire the 8.75% Senior Notes (as defined below), which included principal, interest and a prepayment premium of approximately $162.0 million. The remaining net proceeds were used to reduce borrowings under the Credit Facility.

Using proceeds from the issuance of the 11.25% Senior Notes we fully retired the 8.750% Senior Unsecured Notes due April 15, 2019 ("the 8.75% Senior Notes"). Pursuant to the terms of the indenture, the 8.75% Senior Notes were redeemed at 104.375% of the outstanding principal amount, or approximately $158.5 million, which excludes accrued interest. In connection with this transaction, we recognized a $8.6 million loss on extinguishment during the first quarter of 2018.

Operating Results

Certain of our operating results and statistics for each of the last two years are summarized below:

In thousands, except per share and unit data	Year Ended December 31, 2018	2017
Operating results		
Net income (loss) attributable to common stockholders	$ 11,532	$ (47,453)
Net income (loss) per common share -- basic[1]	0.29	(2.13)
Net income (loss) per common share -- diluted[1]	0.28	(2.13)
Net cash provided by operating activities	88,072	43,446
Operating revenues		
Oil	$ 167,743	$ 80,505
NGLs	18,471	7,086
Natural gas	14,955	6,477
Total operating revenues	$ 201,169	$ 94,068
Total production volumes by product		
Oil (Bbls)	2,483,799	1,579,720
NGLs (Bbls)	817,431	390,185
Natural gas (Mcf)	4,622,815	2,404,620
Total barrels of oil equivalent (6:1)	4,071,700	2,370,675
Daily production volumes by product		
Oil (Bbls/d)	6,805	4,328
NGLs (Bbls/d)	2,239	1,069
Natural gas (Mcf/d)	12,665	6,588
Total barrels of oil equivalent (BOE/d)	11,155	6,495
Average realized prices		
Oil ($ per Bbl)	$ 67.53	$ 50.96
NGLs ($ per Bbl)	22.60	18.48
Natural gas ($ per Mcf)	3.24	2.73
Total oil equivalent, excluding the effect from hedging ($ per BOE)	49.41	39.77
Total oil equivalent, including the effect from hedging ($ per BOE)	44.34	41.08
Operating and other expenses		
Lease operating and gas gathering	$ 26,008	$ 17,385
Production and ad valorem taxes	11,029	5,523
Depreciation, depletion and amortization	83,582	56,957
General and administrative	16,017	12,626
Interest expense	38,943	26,071
Operating and other expenses per BOE		
Lease operating and gas gathering	$ 6.39	$ 7.33
Production and ad valorem taxes	2.71	2.33
Depreciation, depletion and amortization	20.53	24.03
General and administrative	3.93	5.33
Interest expense	9.56	11.00

(1) Basic and diluted earnings per share are calculated using the two-class method. See Footnote 1. *Nature of Business and Presentation* in the Notes to Consolidated Financial Statements included in Item 8.

Production

The table below summarizes our daily production volumes for the years ended 2018 and 2017, and for each of the quarters of 2018:

	2018 Quarters				Year ended December 31,		
	Q1	Q2	Q3	Q4	2018	2017	Change
Oil (Bbls/d)	5,740	6,378	7,183	7,883	6,805	4,328	57%
NGLs (Bbls/d)	965	2,438	2,855	2,675	2,239	1,069	109%
Natural Gas (Mcf/d)	6,435	13,943	14,600	15,561	12,665	6,588	92%
Total (BOE/d)	7,777	11,140	12,471	13,152	11,155	6,495	72%

Total production during 2018 averaged 11,155 BOE/d, an increase of 72% compared to 2017. The annual increase was primarily driven by development of our Eagle Ford acreage throughout the year, with a much smaller increase attributable to incremental production from producing wells acquired in November 2018 through a transaction with Sabine Oil & Gas Corporation.

Our production during 2018 was 81% oil and NGLs, slightly lower than 83% for 2017, due to certain wells brought on-line during 2018 having a higher percentage of natural gas production.

Oil, NGL and Natural Gas Revenues

The table below summarizes our production revenues for 2018 and 2017:

	Year ended December 31,		
In thousands	2018	2017	Change
Oil	$ 167,743	$ 80,505	108%
NGLs	18,471	7,086	161%
Natural Gas	14,955	6,477	131%
Total operating revenues	$ 201,169	$ 94,068	114%

The changes in our oil, NGL and natural gas revenues are due to production quantities and commodity prices, as reflected in the following table (excluding any impact of our commodity derivative contracts):

	Year ended December 31, 2018 vs 2017	
In thousands	Increase in revenues	Percentage increase in revenues
Change in oil, NGL and natural gas revenues due to:		
Increase in production	$ 67,650	63%
Increase in commodity prices	39,451	37%
Total operating revenues	$ 107,101	100%

Excluding the impact of our commodity derivative contracts, our net realized commodity prices and NYMEX differentials were as follows during 2018 and 2017:

	Year ended December 31,		
	2018	2017	Change
Average net realized prices:			
Oil ($/Bbl)	$ 67.53	$ 50.96	33%
NGLs ($/Bbls)	22.60	18.48	22%
Natural gas ($/Mcf)	3.24	2.73	19%
Total ($/BOE)	49.41	39.77	24%
Average NYMEX differentials			
Oil per Bbl	$ 2.76	$ (0.38)	826%
Natural gas per Mcf	0.07	(0.25)	128%

Our average NYMEX oil differential improved year-over-year, by $3.14/Bbl, largely due to the increased spread in 2018 between Louisiana Light Sweet ("LLS") prices, for which substantially all of our crude oil sales were based in 2018 and 2017, and NYMEX WTI benchmark prices.

Our natural gas NYMEX differentials are generally caused by movement in the NYMEX natural gas prices during the month, as most of our natural gas is sold on an index price that is set near the first of each month. While the percentage change in NYMEX natural gas differentials can be large, these differentials are seldom more than a dollar above or below NYMEX price.

Commodity Derivative Contracts

We utilize oil and natural gas derivative contracts to provide an economic hedge of our exposure to commodity price risk associated with anticipated future production and to provide more certainty to our future cash flows. These contracts have historically consisted of fixed-price swaps, collars and basis swaps.

The following table summarizes the net cash (payments) receipts on the Company's commodity derivatives and the relative price impact (per Bbl or Mcf) for the years ended December 31, 2018 and 2017:

	2018		2017	
In thousands, except price impact	Net cash payments	Price impact	Net cash receipts	Price impact
(Payment) receipts on settlements of oil derivatives	$ (22,448)	$ (9.04)	$ 4,560	$ 2.89
(Payment) receipts on settlements of natural gas derivatives	(175)	(0.04)	647	0.27
Total net commodity derivative payments	$ (22,623)		$ 5,207	

Our realized net loss from settlements of commodity derivative contracts was $20.6 million for the year ended December 31, 2018, versus a realized net gain from settlements of commodity derivative contracts of $3.1 million for the year ended December 31, 2017. We realized an average loss of $5.07 per BOE on our oil and natural gas swaps and 2-way oil collar contracts during year ended December 31, 2018, as compared to an average gain of $1.31 per BOE for the year ended December 31, 2017.

Production Expenses

The table below presents detail of production expenses for the years ended December 31, 2018 and 2017:

In thousands, except expense per BOE:	Year Ended December 31, 2018	2017	Change
Production expenses:			
Lease operating and gas gathering	$ 26,008	$ 17,385	50%
Production and ad valorem taxes	11,029	5,523	100%
Depreciation, depletion and amortization	83,582	56,957	47%
Production expenses per BOE:			
Lease operating and gas gathering	$ 6.39	$ 7.33	-13%
Production and ad valorem taxes	2.71	2.33	16%
Depreciation, depletion and amortization	20.53	24.03	-15%

`Lease Operating and Gas Gathering

The table below provides detail of our lease operating and gas gathering expense for the years ended December 31, 2018 and 2017:

In thousands	Year Ended December 31, 2018	2017	Change
Lease operating	$ 23,012	$ 15,549	48%
Gas gathering, processing and transportation	2,996	1,836	63%
Total lease operating and gas gathering expense	$ 26,008	$ 17,385	50%

Lease operating expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for direct labor, water injection and disposal, utilities, materials and supplies comprise the most significant portion of our lease operating expenses. Lease operating expenses do not include general and administrative expenses or production and ad valorem taxes.

Our total lease operating and gas gathering expenses in 2018 were $26.0 million, an increase of 50% from $17.4 million in 2017. This increase was largely due to a 72% increase in production on a per-BOE basis during 2018. On a unit-of-production basis, our lease operating expenses in 2018 were $6.39 per BOE, a decrease of 13% from $7.33 per BOE in 2017, due to operational efficiencies gained from scaled-up production.

Production and Ad Valorem Taxes

Production and ad valorem taxes are paid on produced crude oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties.

The following table provides detail of our production and ad valorem taxes for the years ended December 31, 2018 and 2017:

In thousands	Year Ended December 31, 2018	2017	Change
Production taxes	$ 9,242	$ 4,463	107%
Ad valorem taxes	1,787	1,060	69%
Total production and ad valorem tax expense	$ 11,029	$ 5,523	100%

Our total production and ad valorem taxes in 2018 were $11.0 million, a 100% increase from $5.5 million in 2017. Production taxes increased $4.8 million, or 107%, from $4.5 million in 2017 to $9.2 million in 2018, largely correlating with the 114% increase in production revenues during that time. Ad valorem taxes also increased, by $0.7 million or 69%, from $1.1 million in 2017 to $1.8 million in 2018, due to higher valuations for our properties due to the continued development of our acreage and higher overall oil and natural gas market prices during 2018.

Depreciation, Depletion, and Amortization ("DD&A")

The table below provides detail of our DD&A expense for the years ended December 31, 2018 and 2017:

	Year Ended December 31,		
In thousands	2018	2017	Change
DD&A of proved oil and gas properties	$ 82,420	$ 56,240	47%
Depreciation of other property and equipment	947	578	64%
Accretion of asset retirement obligations	215	139	55%
Total DD&A	$ 83,582	$ 56,957	47%

Capitalized costs attributed to our proved properties are subject to depreciation and depletion. Depreciation and depletion of the cost of oil and natural gas properties is calculated using the unit-of-production method aggregating properties on a field basis. For leasehold acquisition costs and the cost to acquire proved properties, the reserve base used to calculate depreciation and depletion is the sum of proved developed reserves and proved undeveloped reserves. For well costs, the reserve base used to calculate depletion and depreciation is proved developed reserves only. Other property and equipment are carried at cost, and depreciation is calculated using the straight-line method over the estimated useful lives of the assets, ranging from 3 to 5 years.

Our total DD&A expense increased $26.6 million, or 47%, to $83.6 million in 2018 versus $57.0 million in 2017. On a per-BOE basis, DD&A expense decreased $3.44 per BOE, or 15%, to $20.53 per BOE in 2018 from $24.03 per BOE in 2017.

Impairment of Oil and Gas Properties

The Company evaluates impairment of proved and unproved oil and gas properties on a region basis. On this basis, certain regions may be impaired because they are not expected to recover their entire carrying value from future net cash flows. During the third quarter of 2018, we recorded an impairment charge of approximately $12.2 million relating to expiring leases in southern Brazos County included in unproved properties. During 2017, we recorded impairment of $33.4 million, which was comprised of $28.6 million for unproved properties and $4.8 million for proved properties. The 2017 charge was primarily attributable to the impairment of approximately $27.1 million relating to our West Poplar property in Roosevelt County, Montana, during the second quarter of the year.

It is reasonably possible that the Company's estimate of undiscounted future net cash flows may change in the future resulting in the need to impair the carrying value of its properties. See Item 1A. *Risk Factors*, for further discussion.

General and Administrative Expense

G&A expense increased $3.4 million, or 27%, to $16.0 million in the year ended December 31, 2018, from $12.6 million for the year ended December 31, 2017. These increases reflect higher stock-based compensation expense for 2018 (discussed below), as well as higher salaries, bonuses and professional fees incurred during 2018. On a unit-of-production basis, G&A expense decreased 26%, or $1.40 per BOE, from $5.33 per BOE in the year ended December 31, 2017 to $3.93 per BOE in the year ended December 31, 2018.

Stock-based compensation included in G&A was $1.9 million in 2018, versus $1.6 million in 2017. This increase was due to higher valuations of the Company's unvested restricted stock units and stock appreciation rights as of December 31, 2018 as well as compensation related to additional grants which occurred during the second quarter of 2018.

Interest Expense

The table below provides detail of the interest expense from our various long-term obligations for the years ended December 31, 2018 and 2017:

In thousands	Year ended December 31, 2018	Year ended December 31, 2017
Interest expense on Credit Facility	$ 6,500	$ 5,229
Interest expense on 11.25% Senior Notes	27,891	—
Interest expense on 8.75% Senior Notes	—	13,131
Interest expense on Second Lien Notes	—	2,016
Other interest expense	801	393
Total cash interest expense(1)	$ 35,192	$ 20,769
Amortization of debt issuance costs and discounts	3,751	5,302
Total interest expense	$ 38,943	$ 26,071
Per BOE:		
Total cash interest expense(1)	$ 8.64	$ 8.76
Total interest expense	9.56	11.00

(1) Cash interest is presented on an accrual basis.

Our total interest expense in the year ended December 31, 2018 was $38.9 million, a 49% increase from $26.1 million in the year ended December 31, 2017. These increases are primarily due to a combination of higher stated interest rates and principal on the new 11.25% Senior Notes (as defined below) versus the 8.75% Senior Notes (as defined below) that were retired in early January 2018, as well as higher floating rates on our Credit Facility (as defined below), partially offset by the retirement of the remaining Second Lien Notes (as defined below) in June 2017 and lower non-cash interest expense in 2018.

On a unit-of-production basis, total interest expense decreased by 13%, or $1.44 per BOE, from $11.00 per BOE for the year ended December 31, 2017 to $9.56 per BOE for the year ended December 31, 2018.

See Note 9. *Long-Term Debt* in Notes to the Consolidated Financial Statements included in Item 8.for additional information about our long-term debt and interest expense.

Income Taxes

The table below provides further detail of our income tax expense (benefit) for the years ended December 31, 2018 and 2017:

In thousands, except per-BOE amounts and tax rates	Year ended December 31, 2018	Year ended December 31, 2017
Current income tax (benefit) expense	$ (809)	$ 172
Deferred income tax expense (benefit)	7,601	(29,191)
Total income tax expense (benefit)	$ 6,792	$ (29,019)
Average income tax expense (benefit) per BOE	$ 1.67	$ (12.24)
Effective tax rate	26.0%	40.0%
Total net deferred tax liability	$ 12,370	$ 4,769

As a result of the net income before income tax of $26.1 million in the year ended December 31, 2018 and net loss before income tax of $72.5 million from the year ended December 31, 2017, we recorded income tax expense of $6.8 million and income tax benefit of $29 million in the years ended December 31, 2018 and 2017, respectively.

Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. As a result of the reduction in the U.S. corporate income tax rate from 35% to 21% under the Tax Cuts and Jobs Act (the "Act"), we revalued our deferred tax assets and liabilities at December 31, 2017, which resulted in a $4.1 million benefit.

The Act was passed in December 2017, which significantly changes U.S. corporate income tax laws generally taking effect in 2018. We included the impacts of the Act in the consolidated financial statements for the year ended December 31, 2017. The tax provision for the year ended December 31, 2018 reflects the law changes noted above, including the new corporate tax rate of 21%.

The corporate alternative minimum tax ("AMT") for tax years beginning in January 1, 2018 was also repealed. The Act provides that existing AMT credit carryovers are refundable beginning in 2018. As of December 31, 2018, the Company had AMT credit carryovers of $1.2 million that are expected to be fully refunded by 2022.

The deductibility of interest expense for tax years beginning in January 1, 2018 has been limited to 30% of earnings before interest, taxes, depreciation, and amortization for the four years ending 2021. Deductibility of interest expense for tax years beginning in January 1, 2022 will then be limited to 30% of earnings before interest and taxes thereafter. For the year ended December 31, 2018, our deductible interest expense was limited to $25.5 million, which resulted in a $2.3 million deferred tax asset included in the net deferred tax liability on our balance sheet as of December 31, 2018.

Liquidity and Capital Resources

We expect that our primary source of liquidity will be cash flows generated by operating activities and borrowings under our $500,000,000 Senior Secured Credit Facility (the "Credit Facility"). During 2018, we generated cash flows from operations of $88.1 million, after giving effect to $0.3 million change in cash inflows from working capital.

The Company's primary needs for cash are for capital expenditures, acquisitions of oil and natural gas properties, payments of contractual obligations and working capital obligations. We have historically financed our business through cash flows from operations, borrowings under our Credit Facility, the issuance of bonds and equity offerings. As circumstances warrant, we may access the capital markets and issue equity or debt from time to time on an opportunistic basis in a continued effort to optimize our balance sheet and to fund our operations and capital expenditures in the future, dependent upon market conditions and available pricing. Such uses of proceeds may include repayment of our debt, development or acquisition of additional acreage or proved properties, and general corporate purposes. There can be no assurance that future funding transactions will be available on favorable terms, or at all, and we therefore cannot guarantee the outcome of any such transactions.

At December 31, 2018, we had $5.4 million in cash and cash equivalents and approximately $91.5 million of availability under our Credit Facility. We believe that our existing cash and cash equivalents, cash expected to be generated from operations and the availability of borrowing under our Credit Facility will be sufficient to meet our liquidity requirements, operating expenses, anticipated capital expenditures and payments due under our existing credit facility and notes outstanding for at least the next year.

Cash flows for the years ended December 31, 2018 and 2017 are presented below:

	Year ended December 31,	
In thousands	2018	2017
Net cash provided by (used in):		
Operating activities	$ 88,072	$ 43,446
Investing activities	(219,470)	(208,743)
Financing activities	134,215	161,767
Net change in cash	$ 2,817	$ (3,530)

Net Cash Provided by Operating Activities

Net cash provided by operating activities increased $44.7 million, from $43.4 million provided in the year ended December 31, 2017 to $88.1 million provided in the year ended December 31, 2018. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased $44.3 million. This increase is primarily due to higher oil and natural gas production and higher commodity prices. Changes in our operating assets and liabilities between the year ended December 31, 2017 and the year ended December 31, 2018 resulted in a net increase of approximately $0.3 million in net cash provided by operating activities for the year ended December 31, 2018, as compared to the year ended December 31, 2017.

Net Cash Used in Investing Activities

Net cash used in investing activities increased $10.8 million, from $208.7 million used in the year ended December 31, 2017 to $219.5 million used in the year ended December 31, 2018. This increase is primarily due to higher drilling and development costs in 2018, largely offset by larger acquisitions in 2017, including the Marquis and Battlecat properties acquired during the second quarter of 2017.

Net Cash Provided by Financing Activities

Net cash provided by financing activities decreased $27.6 million, from $161.8 million provided in the year ended December 31, 2017 to $134.2 million provided in the year ended December 31, 2018. This decrease primarily results from the net proceeds of $77.8 million received from issuance of our preferred stock in 2017, offset by higher borrowings from our Credit Facility during 2018.

Debt

Senior Secured Credit Facility

In July 2015, we entered into a $500 million Senior Secured Credit Facility with Citibank, N.A., as administrative agent, and other lenders party thereto (as amended, supplemented or modified from time to time), which has a maturity date of July 29, 2020. As of December 31, 2018, $183.0 million was borrowed under the Credit Facility, and the weighted average interest rate on borrowings under the Credit Facility was 5.30%. The Credit Facility may be used for loans and, subject to a $2.5 million sub-limit, letters of credit, and provides for a commitment fee of 0.375% to 0.5% based on the unused portion of the borrowing base.

We were in compliance with the terms of the Credit Facility as of December 31, 2018.

Following are the significant amendments made to the Credit Facility during 2018:

Seventh Amendment. In January 2018, we entered into the Limited Waiver, Borrowing Base Redetermination Agreement, and Amendment No. 7 to the Credit Agreement (the "Seventh Amendment"), which (i) maintained our borrowing base of $160 million until the next redetermination date; (ii) waived the borrowing base redetermination that would otherwise have occurred in connection with the incurrence of the 11.25% Senior Notes (see below), and (iii) amended certain other provisions of the Credit Facility, as set forth more specifically in the Seventh Amendment.

Eighth Amendment. In May 2018, we entered into the Borrowing Base Redetermination Agreement and Amendment No. 8 to Credit Agreement (the "Eighth Amendment"), which (i) increased our borrowing base from $160 million to $190 million and (ii) reallocated the commitments and outstanding loans among lenders, as set forth more specifically in the Eighth Ammendment.

Ninth Amendment. In November 2018, we entered into the Ninth Amendment and Joinder (the "Ninth Amendment"), which (i) increased our borrowing base from $190 million to $275 million; (ii) extended the maturity date of the Credit Facility to November 15, 2023, and (iii) amended certain other provisions of the Credit Facility, as set forth more specifically in the Ninth Amendment.

Issuance of 11.25% Senior Notes

In January 2018, we issued $250.0 million of 11.250% Senior Notes due 2023 (the "11.25% Senior Notes") to U.S.-based institutional investors. The net proceeds of $244.4 million were used to fully retire the 8.75% Senior Notes (as defined below), which included principal, interest and a prepayment premium of approximately $162.0 million. The remaining net proceeds were used to reduce borrowings under the Credit Facility.

The 11.25% Senior Notes mature on January 1, 2023, and bear interest at the rate of 11.25% per year, payable on January 1 and July 1 of each year, beginning July 1, 2018. At any time prior to January 1, 2021, we may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the 11.25% Senior Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 111.25% of the principal amounts redeemed, plus accrued and unpaid interest, provided that at least 65% of the aggregate principal amount of 11.25% Senior Notes originally issued remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering.

At any time prior to January 1, 2021, we may, on any one or more occasions, redeem all or a part of the 11.25% Senior Notes at a redemption price equal to 100% of the principal amount redeemed, plus a "make-whole" premium as of, and accrued and unpaid interest.

On and after January 1, 2021, we may redeem the 11.25% Senior Notes, in whole or in part, plus accrued and unpaid interest, at the following redemption prices: 108.438% after January 1, 2021; 105.625% after January 1, 2022; and 100% after July 1, 2022.

The indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with affiliates, transfer or sell assets, consolidate or merger, or sell substantially all of our assets.

Retirement of 8.75% Senior Notes

Using proceeds from the issuance of the 11.25% Senior Notes, as discussed above, we fully retired the 8.750% Senior Unsecured Notes due April 15, 2019 ("the 8.75% Senior Notes"). Pursuant to the terms of the indenture, the 8.75% Senior Notes were redeemed at 104.375% of the outstanding principal amount, or approximately $158.5 million, which excludes accrued interest. In connection with this transaction, we recognized a $8.6 million loss on extinguishment during the first quarter of 2018. See Note 9. *Long-Term Debt* in the Notes to Consolidated Financial Statements in Item 8. for more information on the 8.75% Senior Notes.

Capital Expenditures

Historical capital expenditures

The table below summarizes our cash capital expenditures incurred for the year ended December 31, 2018:

In thousands	December 31, 2018
Acquisition of oil and gas properties	$ 45,539
Development of oil and gas properties	171,413
Purchases of other property and equipment	2,518
Total capital expenditures, net	$ 219,470

For the year ended December 31, 2018, our capital expenditures were funded with $88.1 million of cash flow from operations, with additional funds provided by borrowings on our Credit Facility.

2019 Capital Spending

We currently anticipate that our full-year 2019 capital budget, excluding acquisitions, will be approximately $107 million to $130 million. This range should provide capital to fund between 17 gross (15.6 net) and 20 gross (18.6 net) wells, all of which will be in our Eagle Ford position in South Texas. Our 2019 capital expenditures may be adjusted as business conditions warrant and the amount, timing and allocation of such expenditures is largely discretionary and within our control. The aggregate amount of capital that we will expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated wells, our drilling results, other opportunities that may become available to us and our ability to obtain capital.

Off-Balance Sheet Arrangements

We have operating leases relating to office space and other minor equipment leases. At December 31, 2018, we had a total of $0.5 million of letters of credit outstanding under our Credit Facility. From time-to-time, we enter into other off-balance sheet arrangements and transactions that give rise to off-balance sheet obligations, including non-operated drilling commitments, termination obligations under rig contracts, frac spread contracts, firm transportation, gathering, processing and disposal commitments, and contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices. See Note 14. *Commitments and Contingencie*s in Notes to Consolidated Financial Statements in Item 8. for more information.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires that we select certain accounting policies and make certain estimates and judgments regarding the application of those policies. Our significant accounting policies are included in Note 1. *Basis of Presentation*, of the Notes to Consolidated Financial Statements in Item 8. These policies, along with the underlying assumptions and judgments by our management in their application, have a significant impact on our consolidated financial statements. Following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in the preparation of our financial statements.

Estimates of Reserve Quantities

Reserve estimates are inexact and may change as additional information becomes available. Furthermore, estimates of oil and gas reserves are projections based on engineering data. There are uncertainties inherent in the interpretation of such data, as well as the projection of future rates of production and timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. Accordingly, there can be no assurance that ultimately, the reserves will be produced, nor can there be assurance that the proved undeveloped reserves will be developed within the period anticipated. All reserve reports prepared by the independent third-party reserve engineers are reviewed by our senior management team, including the Chief Executive Officer and Senior Vice President-Operations. Estimated reserves are often subject to future revisions, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions in reserve quantities. Reserve revisions will inherently lead to adjustments of DD&A rates. We cannot predict the types of reserve revisions that will be required in future periods. A 10% increase or decrease in our estimates of total proved reserves at December 31, 2018 would have decreased or increased our DD&A expense of proved oil and gas properties by approximately $2.1 million or 2.6%, or $2.6 million or 3.1%, respectively, for the year ended December 31, 2018.

Oil and Natural Gas Properties

We use the successful efforts method of accounting to account for our oil and gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Our policy is to expense the costs of such exploratory wells if a determination of proved reserves has not been made within a 12-month period after drilling is complete. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred, whether productive or nonproductive.

Capitalized costs attributed to the proved properties are subject to depreciation and depletion. Depreciation and depletion of the cost of oil and gas properties is calculated using the units-of-production method aggregating properties on a field basis. For leasehold acquisition costs and the cost to acquire proved properties, the reserve base used to calculate depreciation and depletion is the sum of proved developed reserves and proved undeveloped reserves. For well costs, the reserve base used to calculate depletion and depreciation is proved developed reserves only.

Unproved properties consist of costs incurred to acquire unproved leases. Unproved lease acquisition costs are capitalized until the leases expire or when the Company specifically identifies leases that will revert to the lessor, at which time the Company expenses the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as an impairment of oil and gas properties in the consolidated statement of operations, as applicable. Unproved oil and gas property costs are transferred to proven oil and gas properties if the properties are subsequently determined to be productive or are assigned proved reserves. Unproved oil and gas properties are assessed periodically for impairment based on remaining lease terms, drilling results, reservoir performance, future plans to develop acreage, and other relevant factors.

It is common for operators of oil and natural gas properties to request that joint interest owners pay for large expenditures, typically for drilling new wells, in advance of the work commencing. This right to call for cash advances is typically found in the joint operating agreement that joint interest owners in a property adopt. As an operator, we record these advance payments in other current liabilities and relieve this account when the actual expenditure is billed by us in the monthly joint interest billing statement.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and any gain or loss is recognized. On the sale or retirement of a partial unit of a proved property, a pro-rata portion of the cost and related accumulated depreciation, depletion and amortization are eliminated from the property accounts.

Impairment of Long-Lived Assets

The carrying value of the oil and gas properties and other related property and equipment is periodically evaluated under the provisions of Accounting Standards Codification ("ASC") 360, *Property, Plant, and Equipment*. ASC 360 requires long-lived assets and certain identifiable intangibles to be reviewed for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. When it is determined that the estimated future net cash flows of an asset will not be sufficient to recover its carrying amount, an impairment loss must be recorded to reduce the carrying amount to its estimated fair value. Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows and an asset's fair value. These judgments and assumptions include such matters as the estimation of oil and gas reserve quantities, risks associated with the different categories of oil and gas reserves, the timing of development and production, expected future commodity prices, capital expenditures, production costs, and appropriate discount rates.

The Company evaluates impairment of proved and unproved oil and gas properties on a region-level basis. On this basis, certain regions may be impaired because they are not expected to recover their entire carrying value from future net cash flows.

Derivative Financial Instruments

We use derivative financial instruments to hedge our exposure to changes in commodity prices arising in the normal course of business. The principal derivatives that may be used are commodity price swap, option and costless collar contracts. The use of these instruments is subject to policies and procedures as approved by our board directors. We do not trade in derivative financial instruments for speculative purposes. None of our derivative contracts have been designated as cash flow hedges for accounting purposes. Derivative financial instruments are initially recognized at cost, if any, which approximates fair value. Subsequent to initial recognition, derivative financial instruments are recognized at fair value. The derivatives are valued on a mark-to-market valuation, and the gain or loss on re-measurement to fair value is recognized through the statement of operations. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, option pricing models, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

The counterparties to our derivative instruments are not known to be in default on their derivative positions. However, we are exposed to credit risk to the extent of nonperformance by the counterparty in the derivative contracts. We believe credit risk is minimal and do not anticipate such nonperformance by such counterparties.

Asset Retirement Obligations

We account for asset retirement obligations ("AROs") under ASC 410, *Asset Retirement and Environmental Obligations.* ASC 410 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Oil and gas producing companies incur such a liability upon acquiring or drilling a well. Under ASC 410, an asset retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to producing properties in the accompanying consolidated balance sheet, which is allocated to expense over the useful life of the asset. Periodic accretion of the discount on asset retirement obligations is recorded as an expense in the accompanying consolidated statement of operations. The estimation of future costs associated with the dismantlement, abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a number of years in the future. Such cost estimates could be subject to revisions in subsequent years due to changes in regulatory requirement, technological advances and other factors that are difficult to predict.

There are many variables in estimating AROs. We primarily use the remaining estimated useful life from the year-end independent third-party reserve reports in estimating when abandonment could be expected for each property based on field or industry practices. We expect to see our calculations impacted significantly if interest rates move from their current levels, as the credit-adjusted-risk-free-rate is one of the variables used on a quarterly basis. Our technical team has developed a standard cost estimate based on the historical costs, industry quotes and depth of wells. Unless we expect a well's plugging cost to be significantly different than a normal abandonment, we use this estimate. The resulting estimate, after application of an inflation factor and a discount factor, could differ from actual results.

Income Taxes

We follow the asset and liability method in accounting for income taxes in accordance with ASC 740, *Income Taxes.* Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, operating losses and tax credit carryforwards.

Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which these temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. In addition, a valuation allowance is established to reduce any deferred tax asset for which it is determined that it is more likely than not that some portion of the deferred tax asset will not be realized.

Changes in our expectations regarding our future taxable income (which is materially impacted by volatility in commodity prices), can result in our recording of a valuation allowance against our deferred tax assets. We would record this valuation allowance when our judgment is that our existing U.S. federal net operating loss carryforwards are not, on a more-likely-than-not basis, recoverable in future years. We will continue to evaluate the need for a valuation allowance based on current and expected earnings and other factors and adjust it accordingly.

We evaluate uncertain tax positions, which requires significant judgments and estimates regarding the recoverability of deferred tax assets, the likelihood of the outcome of examinations of tax positions that may or may not be currently under review, and potential scenarios involving settlements of such matters. Changes in these estimates could materially impact the consolidated financial statements.

Recently Issued Accounting Pronouncements

See "Note 2. *Recently Issued Accounting Pronouncements*" of the Notes to Consolidated Financial Statements in Item 8. for discussion of the recent accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

We are exposed to a variety of financial market risks including interest rate, commodity prices and liquidity risk. Our risk management focuses on the volatility of commodity markets and protecting cash flow in the event of declines in commodity pricing. We utilize derivative financial instruments to hedge certain risk exposures. Our financial instruments consist mainly of deposits with banks, short-term investments, accounts receivable, derivative financial instruments, our Senior Secured Credit Facility, bonds and payables. The main purpose of non-derivative financial instruments is to raise finance for our operations.

Financial risk management is carried out by our management. Our board of directors sets financial risk management policies and procedures to which our management is required to adhere. Our management identifies and evaluates financial risks and enters into financial risk instruments to mitigate these risk exposures in accordance with the policies and procedures outlined by our board of directors.

Commodity Price Risk

As a result of our operations, we are exposed to commodity price risk arising from fluctuations in the prices of crude oil, NGLs and natural gas. The demand for, and prices of, crude oil, NGLs and natural gas are dependent on a variety of factors, including supply and demand, weather conditions, the price and availability of alternative fuels, actions taken by governments and international cartels and global economic and political developments.

The following table shows the fair value of our derivative contracts and the hypothetical result from a 10% change in commodity prices as of December 31, 2018. We remain at risk for possible changes in the market value of commodity derivative instruments; however, such risks could be mitigated by price changes in the underlying physical commodity (in thousands):

		Hypothetical Fair Value	
(in thousands)	Fair Value	10% Increase In Commodity Price	10% Decrease In Commodity Price
Swaps	$ 22,692	$ 4,361	$ 41,023

Our board of directors reviews oil and natural gas hedging on a quarterly basis. Reports providing detailed analysis of our hedging activity are continually monitored. We sell our oil and natural gas on market using NYMEX market spot rates reduced for basis differentials in the basins from which we produce. We use swap contracts to manage our commodity price risk exposure. Our primary commodity risk management objectives are to protect returns on our drilling and completion activity as well as reduce volatility in our cash flows. Management makes recommendations on hedging that are approved by the board of directors before implementation. We enter into hedges for oil using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our board of directors.

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

Interest Rate Risk

As of December 31, 2018, we had $183.0 million outstanding under the Credit Facility, which is subject to floating market rates of interest. Borrowings under the Credit Facility bear interest at a fluctuating rate that is tied to an adjusted base rate or LIBOR, at our option. Any increase in this interest rate can have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at December 31 2018, a 100-basis-point change in interest rates would change our annualized interest expense by approximately $1.9 million.

Counterparty and Customer Credit Risk

In connection with our hedging activity, we have exposure to financial institutions in the form of derivative transactions. The counterparties on our derivative instruments currently in place have investment-grade credit ratings. We expect that any future derivative transactions we enter into will be with these counterparties or our lenders under our Credit Facility that will carry an investment-grade credit rating.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history and financial resources of our customers, but we do not require our customers to post collateral.

Item 8. Financial Statements and Supplementary Data.

The financial statements and supplementary information required by this Item appears on pages F-1 through F-33 of this Annual Report on 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

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) was performed under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Accounting Officer. Based on that evaluation, our Chief Executive Officer and Chief Accounting Officer concluded that our disclosure controls and procedures were not effective as of December 31, 2018 (as described more fully below), to ensure that information that is required to be disclosed in the reports the Company files and submits under the Securities Exchange Act of 1934 is recorded; that it is processed, summarized and reported within the time periods specified in the SEC's rules and forms; and that information that is required to be disclosed under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and our Chief Accounting Officer, as appropriate to allow timely decisions regarding required disclosure.

Remediation of Previous Material Weakness

As previously discussed in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2018, during the third quarter of 2018, our management determined that a material weakness existed in the Company's internal control over financial reporting, specifically, related to the Company's review of its depreciation, depletion and amortization ("DD&A") expense calculation. Instead of using updated oil and natural gas reserve estimates to calculate DD&A expense calculations looking back to the beginning of the applicable fiscal year, the Company should have used the updated oil and natural gas reserve estimates to calculate DD&A looking back to the beginning of the applicable current quarter. This error resulted in a material misstatement of the financial statements and required restatement of the financial statements included in the Company's Form 10-K for the fiscal year ended December 31, 2017 and in the Company's Form 10-Q for the quarterly periods ended March 31, 2018 and June 30, 2018.

To remediate the material weakness described above and enhance our internal control over financial reporting, management implemented new controls over calculating, recording and reviewing DD&A expense and additional training, beginning in the third quarter of 2018. As a result of the implementation of these controls, management has determined that the foregoing material weakness has been remediated as of December 31, 2018.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Accounting Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this report based on the framework in "Internal Control - Integrated Framework" (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Accounting Officer concluded that our internal control over financial reporting was not effective, as of December 31, 2018, to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

Prior to filing this Annual Report on Form 10-K, an error was discovered related to the calculation of the Company's basic and diluted earnings per share for the year ended December 31, 2018. This error was identified and corrected prior to the filing of this Annual Report on Form 10-K but could have resulted in a material misstatement of the financial statements. This error was the result of inadequate design of controls pertaining to the Company's review of its earnings per share calculation. As such, the deficiency represents a material weakness in the Company's internal control over financial reporting at December 31, 2018.

Management is actively engaged in the planning for, and implementation of, remediation efforts to address the material weakness identified above. The remediation plan includes i) new controls over calculating and recording basic and diluted earnings per share and ii) additional training. New controls consist of enhancing the Company's formal quarterly and annual close procedures, beginning with the quarter ended March 31, 2019, to ensure (a) proper review of all potentially dilutive or participating instruments and (b) adequate time for preparation and review of the weighted average share calculation. Additional training will consist of internal review of technical guidance, attendance of external training sessions, preparation of quarter and year end calculations, and review and feedback by the Chief Accounting Officer.

Management believes the measures described above and others that may be implemented will remediate the material weaknesses that we have identified. As management continues to evaluate and improve internal control over financial reporting, we may decide to take additional measures to address control deficiencies or determine to modify, or in appropriate circumstances not to complete, certain of the remediation measures identified.

Changes in Internal Controls

Subject to these remediation efforts, that were implemented after December 31, 2018, and other than the remediation efforts related to the previous material weakness noted above, there have been no significant changes in the Company's internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Because we are an "emerging growth company" under the JOBS Act, our independent registered public accounting firm, BDO USA, LLP, is not required to issue an attestation report on our internal control over financial reporting.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error, and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Our board of directors has adopted a Code of Business Conduct and Ethics applicable to all officers, directors, and employees, which is available on our website at www.lonestarresources.com in the *Shareholder Information* section under *Governance*. We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics, as well as NASDAQ's requirements to disclose waivers with respect to directors and executive officer, by posting such information on our website at the address and location specified above.

The information concerning our executive officers and directors in response to this item is contained above in part under the caption *Executive Officers and Directors* at the end of Part I of this Annual Report on Form 10-K. The remainder of the response to this item is contained in the Proxy Statement for our 2019 Annual Meeting of Stockholders and is incorporated herein by reference.

Item 11. Executive Compensation.

The information required by this item will be included in our Proxy Statement for our 2019 Annual Meeting of Stockholders and is incorporated herein by reference.

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

The information required by this item will be included in our Proxy Statement for our 2019 Annual Meeting of Stockholders and is incorporated herein by reference.

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

The information required by this item will be included in our Proxy Statement for our 2019 Annual Meeting of Stockholders and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

The information required by this item will be included in our Proxy Statement for our 2019 Annual Meeting of Stockholders and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

The consolidated financial statements and related notes, together with the report of BDO USA, LLP, Independent Registered Public Accounting Firm, appear in Part II Item 8. *Financial Statements and Supplementary Data* of this Form 10-K.

(a)(2) Financial Statements Schedules

All schedules have been omitted because they are not required or because the required information is given in the Consolidated Financial Statements or Notes thereto.

(a)(3) Exhibits

The Exhibits listed below on the Exhibit Index are filed or incorporated by reference as part of this Form 10-K.

Exhibit Index

Exhibit Number	Description	Incorporated by Reference			Filing Date	Filed/ Furnished Herewith
		Form	File No.	Exhibit		
2.1	Scheme Implementation Agreement, by and between Lonestar Resources US Inc. and Lonestar Resources Limited, executed on December 28, 2015	10-12B	001-37670	2.1	12/31/15	
2.2	Purchase and Sale Agreement by and between Lonestar Resources US Inc. and Battlecat Oil & Gas, LLC, dated as of May 26, 2017	8-K	001-37670	2.1	6/2/17	
2.3	Amendment No. 1, dated June 15, 2017, to the Purchase and Sale Agreement, by and between Lonestar Resources US Inc. and Battlecat Oil & Gas, LLC, dated May 26, 2017	8-K	001-37670	2.1	6/21/17	
2.4	Purchase and Sale Agreement by and between Lonestar Resources US Inc. and SN Marquis LLC, dated as of May 26, 2017	8-K	001-37670	2.2	6/2/17	
2.5	Amendment No. 1, dated June 15, 2017, to the Purchase and Sale Agreement by and between Lonestar Resources US Inc. and SN Marquis LLC, dated as of May 26, 2017	8-K	001-37670	2.2	6/21/17	
3.1	Certificate of Incorporation of Lonestar Resources US Inc.	10-12B	001-37670	3.1	12/31/15	
3.2	Certificate of Amendment to the Certificate of Incorporation of Lonestar Resources US Inc.	10-K	001-37670	3.2	3/23/17	
3.3	Certificate of Amendment to Certificate of Incorporation of Lonestar Resources US Inc., dated May 24, 2017	8-K	001-37670	3.1	5/26/17	
3.4	Amended and Restated Bylaws of Lonestar Resources US Inc.	8-K	001-37670	3.1	4/7/17	
3.5	Certificate of Designations of Series B Convertible Preferred Stock	8-K	001-37670	3.1	6/21/17	
3.6	Certificate of Designations of Series A-1 Convertible Participating Preferred Stock	8-K	001-37670	3.2	6/21/17	
3.7	Certificate of Designations of Series A-2 Convertible Participating Preferred Stock	8-K	001-37670	3.3	6/21/17	
4.1	Registration Rights Agreement dated August 2, 2016 by and among Lonestar Resources US Inc., Leucadia National Corporation and Juneau Energy, LLC.	8-K	001-37670	4.1	8/3/16	
4.2	Amendment No. 1, dated June 15, 2017, to the Registration Rights Agreement by and among Lonestar Resources US Inc., Leucadia National Corporation and Juneau Energy, LLC (n/k/a JETX Energy, LLC)	8-K	001-37670	4.4	6/21/17	
4.3	Registration Rights Agreement, dated as of June 15, 2017, by and between Lonestar Resources US Inc. and SN UR Holdings, LLC	8-K	001-37670	4.2	6/21/17	
4.4	Registration Rights Agreement, dated as of June 15, 2017, by and between Lonestar Resources US Inc. and Chambers Energy Capital III, LP	8-K	001-37670	4.3	6/21/17	
4.5	Indenture, dated as of January 4, 2018, by and among Lonestar Resources America Inc., the subsidiary guarantors named therein and UMB Bank, N.A. as Trustee.	8-K	001-37670	4.1	1/9/18	
10.1	Amended and Restated Securities Purchase Agreement by and between Lonestar Resources US Inc., and Chambers Energy Capital III, LP, dated June 15, 2017	8-K	001-37670	10.1	6/21/17	

10.2	Credit Agreement, dated July 28, 2015, among Lonestar Resources America Inc., Citibank, N.A., as Administrative Agent, and the guarantors and lenders party thereto.	10-12B	001-37670	10.3	12/31/15	
10.3	First Amendment to Credit Agreement, dated effective April 29, 2016, among Lonestar Resources America Inc., Citibank, N.A., as Administrative Agent, and the guarantors and lenders party thereto.	10-12B/A	001-37670	10.5	6/9/16	
10.4	Second Amendment to Credit Agreement, dated effective May 19, 2016, among Lonestar Resources America Inc., Citibank, N.A., as Administrative Agent, and the guarantors and lenders party thereto.	10-12B/A	001-37670	10.6	6/9/16	
10.5	Third Amendment to Credit Agreement and Limited Waiver, dated effective July 27, 2016, among Lonestar Resources America Inc., Citibank, N.A., as Administrative Agent, and the guarantors and lenders party thereto.	8-K	001-37670	10.1	8/2/16	
10.6	Fourth Amendment to Credit Agreement dated effective November 23, 2016, among Lonestar Resources America Inc., Citibank N.A., as administrative agent, and lenders party thereto.	10-K/A	001-37670	10.7	11/2/18	
10.7	Fifth Amendment to Credit Agreement and Limited Waiver dated effective December 29, 2016, among Lonestar Resources America Inc., Citibank, N.A., as administrative agent and lenders party thereto.	10-K/A	001-37670	10.8	11/2/18	
10.8	Sixth Amendment and Joinder dated June 15, 2017 to the Credit Agreement dated July 28, 2015 by and among Lonestar Resources America, Inc., the subsidiary guarantors party thereto, the lenders party thereto and Citibank, N.A., Inc. as administrative agent and issuing bank.	8-K	001-37670	10.2	6/21/17	
10.9	Limited Waiver, Borrowing Base Redetermination and Amendment No. 7 to Credit Agreement, dated as of January 4, 2018, by and among Lonestar Resources America Inc., the subsidiary guarantors party thereto, the lenders party thereto and Citibank, N.A., as administrative agent and issuing bank.	8-K	001-37670	10.1	1/9/18	
10.10	Limited Waiver Agreement, dated as of March 28, 2018, among Lonestar Resources America Inc., the guarantor parties hereto, Citibank, N.A., as administrative agent and issuing bank, and lenders party thereto.	10-K/A	001-37670	10.11	11/2/18	
10.11	Borrowing Base Redetermination Agreement and Amendment No. 8 to Credit Agreement.	8-K	001-37670	10.1	5/24/18	
10.12†	Lonestar Resources US Inc. Amended and Restated 2016 Incentive Plan, as amended and restated as of May 24, 2018.	8-K	001-37670	10.2	5/24/18	
10.13	Ninth Amendment and Joinder to Credit Agreement dated November 15, 2018, among Lonestar Resources America Inc., the Guarantors party hereto, Citibank, N.A, as administrative agent and issuing bank, and lenders party thereto.	8-K	001-37670	10.1	11/19/18	
21.1	List of subsidiaries of Lonestar Resources US Inc.					*
23.1	Consent of BDO USA, LLP					*
23.2	Consent of W.D. Von Gonten & Co.					*
31.1	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer					*

31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Accounting Officer					*
32.1	Section 1350 Certification of Chief Executive Officer					**
32.2	Section 1350 Certification of Chief Accounting Officer					**
99.1	Report of W.D. Von Gonten & Co. regarding the Company's estimated proved reserves as of December 31, 2017, dated February 20, 2018	10-K/A	001-37670	99.2	11/2/18	
99.2	Report of W.D. Von Gonten & Co. regarding the Company's estimated proved reserves as of December 31, 2018, dated February 19, 2019					*
101.INS	XBRL Instance Document					*
101.SCH	XBRL Taxonomy Extension Schema Document					*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					*

* Filed herewith.

** Furnished herewith

† Management contract or compensatory plan or arrangement.

Item 16. Form 10-K Summary

None.

SIGNATURES

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

LONESTAR RESOURCES US INC.

March 13, 2019

/s/ Frank D. Bracken, III

Frank D. Bracken, III

Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Name	Title	Date
/s/ Frank D. Bracken, III Frank D. Bracken, III	Chief Executive Officer and Director (Principal Executive Officer)	March 13, 2019
/s/ Jason N. Werth Jason N. Werth	Chief Accounting Officer (Principal Financial and Accounting Officer)	March 13, 2019
/s/ John Pinkerton John Pinkerton	Chairman of the Board	March 13, 2019
/s/ Henry B. Ellis Henry B. Ellis	Director	March 13, 2019
/s/ Daniel R. Lockwood Daniel R. Lockwood	Director	March 13, 2019
/s/ Matthew B. Ockwood Matthew B. Ockwood	Director	March 13, 2019
/s/ Stephen H. Oglesby Stephen H. Oglesby	Director	March 13, 2019
/s/ Phillip Z. Pace Phillip Z. Pace	Director	March 13, 2019
/s/ Randy L. Wolsey Randy L. Wolsey	Director	March 13, 2019

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Lonestar Resources US Inc.
Fort Worth, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Lonestar Resources US, Inc. (the "Company") and subsidiaries as of December 31, 2018 and 2017, the related consolidated statements of operations, changes in stockholders' equity, and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company and subsidiaries at December 31, 2018 and 2017, and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2013.

Dallas, Texas

March 13, 2019

PART I—FINANCIAL INFORMATION

Item 8. Financial Statements.

Lonestar Resources US Inc.
Consolidated Balance Sheets
(In thousands, except share and per share data)

	December 31, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 5,355	$ 2,538
Accounts receivable		
Oil, natural gas liquid and natural gas sales	15,103	12,289
Joint interest owners and other, net	4,541	794
Related parties	301	162
Derivative financial instruments	15,841	472
Prepaid expenses and other	1,966	2,365
Total current assets	43,107	18,620
Property and equipment		
Oil and gas properties, using the successful efforts method of accounting		
Proved properties	960,711	747,370
Unproved properties	81,850	81,511
Other property and equipment	17,727	15,763
Less accumulated depreciation, depletion, amortization and impairment	(369,529)	(274,374)
Property and equipment, net	690,759	570,270
Derivative financial instruments	7,302	—
Other non-current assets	2,944	2,918
Total assets	$ 744,112	$ 591,808
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 18,260	$ 25,901
Accounts payable – related parties	181	389
Oil, natural gas liquid and natural gas sales payable	13,022	8,747
Accrued liabilities	28,128	16,583
Derivative financial instruments	430	12,336
Total current liabilities	60,021	63,956
Long-term liabilities		
Long-term debt	436,882	301,155
Asset retirement obligations	7,195	5,649
Deferred tax liability, net	12,370	4,769
Equity warrant liability	366	508
Equity warrant liability - related parties	689	963
Derivative financial instruments	21	9,802
Other non-current liabilities	4,021	1,316
Total long-term liabilities	461,544	324,162
Commitments and contingencies (Note 14)		
Stockholders' equity		
Class A voting common stock, $0.001 par value, 100,000,000 shares authorized, 24,645,825 and 24,506,647 issued and outstanding, respectively	142,655	142,655
Class B non-voting common stock, $0.001 par value, 5,000 shares authorized, 0 and 2,500 issued and outstanding, respectively	—	—
Series A-1 convertible participating preferred stock, $0.001 par value, 91,784 and 83,968 shares issued and outstanding, respectively	—	—
Additional paid-in capital	174,379	174,871
Accumulated deficit	(94,487)	(113,836)
Total stockholders' equity	222,547	203,690
Total liabilities and stockholders' equity	$ 744,112	$ 591,808

See accompanying Notes to Consolidated Financial Statements.

Lonestar Resources US Inc.
Consolidated Statements of Operations
(In thousands, except share and per share data)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Revenues		
Oil sales	$ 167,743	$ 80,505
Natural gas liquid sales	18,471	7,086
Natural gas sales	14,955	6,477
Total revenues	201,169	94,068
Expenses		
Lease operating and gas gathering	26,008	17,385
Production and ad valorem taxes	11,029	5,523
Depreciation, depletion and amortization	83,582	56,957
Loss on sale of oil and gas properties	—	466
Impairment of oil and gas properties	12,169	33,413
General and administrative	16,017	12,626
Acquisition costs and other	1,821	3,139
Total expenses	150,626	129,509
Income (loss) from operations	50,543	(35,441)
Other income (expense)		
Interest expense	(38,943)	(26,071)
Unrealized gain on warrants	416	3,088
Gain (loss) on derivative financial instruments	22,744	(14,080)
Loss on extinguishment of debt	(8,620)	—
Total other expense, net	(24,403)	(37,063)
Income (loss) before income taxes	26,140	(72,504)
Income tax (expense) benefit	(6,792)	29,019
Net income (loss)	19,348	(43,485)
Preferred stock dividends	(7,816)	(3,968)
Net income (loss) attributable to common stockholders	$ 11,532	$ (47,453)
Net income (loss) per common share attributable to common stockholders		
Basic	$ 0.29	$ (2.13)
Diluted	$ 0.28	$ (2.13)
Weighted Average Shares Outstanding		
Basic	24,619,730	22,252,149
Diluted	24,801,143	22,252,149

See accompanying Notes to Consolidated Financial Statements.

Lonestar Resources US Inc.
Consolidated Statements of Changes in Stockholders' Equity
(In thousands, except share data)

	Class A Common Stock		Series A-1 Preferred Stock		Series B Preferred Stock		Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Shares	Amount			
Balances at December 31, 2016	21,822,015	$142,652	—	$ —	—	$ —	$ 87,260	$ (70,351)	$ 159,561
Shares issued for asset acquisitions	—	—	5,400	—	2,684,632	3	10,792	—	10,795
Conversion of Series A-2 Preferred	—	—	76,577	—	—	—	75,504	—	75,504
Conversion of Series B Preferred	2,684,632	3	—	—	(2,684,632)	(3)	—	—	—
Payment-in-kind dividends	—	—	1,991	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	—	—	1,315	—	1,315
Net loss	—	—	—	—	—	—	—	(43,485)	(43,485)
Balances at December 31, 2017	24,506,647	$142,655	83,968	$ —	—	$ —	$ 174,871	$ (113,836)	$ 203,690
Shares issued pursuant to stock-based compensation plan	139,178	—	—	—	—	—	(601)	—	(601)
Retirement of Class B Common Stock	—	—	—	—	—	—	(10)	—	(10)
Payment-in-kind dividends	—	—	7,816	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	—	—	119	—	119
Net income	—	—	—	—	—	—	—	19,348	19,348
Balances at December 31, 2018	24,645,825	$142,655	91,784	$ —	—	$ —	$ 174,379	$ (94,487)	$ 222,547

See accompanying Notes to Consolidated Financial Statements.

Lonestar Resources US Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cash flows from operating activities		
Net income (loss)	$ 19,348	$ (43,485)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depreciation, depletion and amortization	83,582	56,957
Stock-based compensation	1,707	1,629
Stock-based payments	(601)	—
Deferred taxes	7,601	(29,191)
(Gain) loss on derivative financial instruments	(22,744)	14,080
Settlements of derivative financial instruments	(22,623)	5,207
Impairment of oil and natural gas properties	12,169	33,413
Loss on abandonment of property and equipment	170	—
Non-cash interest expense	5,194	4,571
Unrealized gain on warrants	(416)	(3,088)
Changes in operating assets and liabilities		
Accounts receivable	(5,391)	(6,851)
Prepaid expenses and other assets	(3,296)	833
Accounts payable and accrued expenses	13,372	9,371
Net cash provided by operating activities	88,072	43,446
Cash flows from investing activities		
Acquisition of oil and gas properties	(45,539)	(113,726)
Development of oil and gas properties	(171,413)	(81,875)
Purchases of other property and equipment	(2,518)	(13,142)
Net cash used in investing activities	(219,470)	(208,743)
Cash flows from financing activities		
Proceeds from borrowings	423,745	123,968
Payments on borrowings	(289,520)	(34,017)
Proceeds from sale of preferred stock	—	77,800
Repurchase and retirement of Class B Common Stock	(10)	—
Cost to issue equity	—	(3,296)
Payments of debt issuance costs and other	—	(2,688)
Net cash provided by financing activities	134,215	161,767
Increase (decrease) in cash and cash equivalents	2,817	(3,530)
Cash and cash equivalents, beginning of the period	2,538	6,068
Cash and cash equivalents, end of the period	$ 5,355	$ 2,538
Supplemental information:		
Cash paid for taxes	$ 1,242	$ 2,474
Cash paid for interest	24,395	20,389
Non-cash investing and financing activities:		
Asset retirement obligation	$ 1,331	$ 2,827
(Decrease) increase in liabilities for capital expenditures	(4,603)	8,379
Preferred stock issued for business acquisitions	—	10,795

See accompanying Notes to Consolidated Financial Statements.

1. Basis of Presentation

Organization and Nature of Operations

Lonestar Resources US Inc. (“Lonestar” or the "Company") is a Delaware corporation whose common stock is listed and traded on the Nasdaq Global Select Market under the symbol “LONE”. The Company is an independent oil and natural gas company focused on the exploration, development and production of unconventional oil, natural gas liquids and natural gas in the Eagle Ford Shale play in South Texas.

Principles of Reporting and Consolidation

The consolidated financial statements have been prepared using the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America ("GAAP”) and include the accounts of Lonestar and entities in which we hold a controlling financial interest. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. All intercompany balances and transactions have been eliminated.

Certain reclassifications have been made to the 2017 consolidated financial statement and footnote amounts in order to conform them to the 2018 presentation.

Use of Estimates

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. Depletion of oil and gas properties and impairment of proved and unproved oil and gas properties, in part, is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Significant estimates underlying these financial statements also include the estimated costs and timing of asset retirement obligations, the fair value of commodity derivatives, the fair value of warrants, restricted stock units and stock appreciation rights, accruals related to oil and natural gas volumes and revenues, and estimates related to income taxes. Changes in facts and circumstances or additional information may result in revised estimates, actual results may differ from these estimates.

Cash Equivalents

The Company considers all highly-liquid investments to be cash equivalents if they have maturities of three months or less when purchased.

Concentrations and Credit Risk

Lonestar's financial instruments exposed to concentrations of credit risk consist primarily of cash and cash equivalents, accounts receivable and derivative receivables (see Note 4. *Commodity Price Risk Activities*). The Company places its cash and cash equivalents with reputable financial institutions. At times, the balances deposited may exceed amounts covered by insurance provided by the U.S. Federal Deposit Insurance Corporation (“FDIC”). The Company has not incurred any losses related to amounts in excess of FDIC limits.

Substantially all of the Company’s accounts receivable are due from either purchasers of oil, NGL and natural gas or working interest partners in oil and natural gas wells for which a subsidiary of the Company serves as the operator. Generally, operators of oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells. The Company’s receivables are generally unsecured.

For the year ended December 31, 2018, oil, NGL and natural gas revenues from Enterprise Crude Oil LLC, Vitol Inc., Shell Trading (US) Company, Texla Energy Management, Inc. and NGL Crude Logistics LLC, represented 27%, 16%, 15%, 15%, and 11%, respectively, of total revenues. For the year ended December 31, 2017, oil, NGL and natural gas revenues from Vitol Inc., Shell Trading (US) Company, Texla Energy Management, Inc., Trafigura AG, and NGL Crude Logistics LLC represented 35%, 20%, 16%, 14% and 10%, respectively, of total revenues.

As of December 31, 2018, receivables relating to oil, NGL and natural gas sales from Enterprise Crude Oil LLC, Phillips 66, Shell Trading (US) Company, and NGL Crude Logistics LLC represented 37%, 23%, 22%, and 10%, respectively, of total receivables. As of December 2017, receivables relating to oil, NGL and natural gas sales from Vitol Inc., Shell Trading (US) Company and NGL Crude Logistics LLS represented 59%, 19% and 17%, respectively, of total receivables.

Oil and Natural Gas Properties

Lonestar uses the successful efforts method of accounting to account for its oil and natural gas properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The Company's policy is to expense the costs of such exploratory wells if a determination of proved reserves has not been made within a 12-month period after drilling is complete. As of December 31, 2018, the Company did not have any capitalized exploratory well costs that were pending determination of proved reserves. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred, whether productive or nonproductive.

Capitalized costs attributed to the proved properties are subject to depreciation and depletion. Depreciation and depletion of the cost of oil and gas properties is calculated using the units-of-production method aggregating properties on a field basis. For leasehold acquisition costs and the cost to acquire proved properties, the reserve base used to calculate depreciation and depletion is the sum of proved developed reserves and proved undeveloped reserves. For well costs, the reserve base used to calculate depletion and depreciation is proved developed reserves only.

Unproved properties consist of costs incurred to acquire unproved leases. Unproved lease acquisition costs are capitalized until the leases expire or when the Company specifically identifies leases that will revert to the lessor, at which time the Company expenses the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as an impairment of oil and gas properties in the consolidated statement of operations, as applicable. Unproved oil and gas property costs are transferred to proven oil and gas properties if the properties are subsequently determined to be productive or are assigned proved reserves. Unproved oil and gas properties are assessed periodically for impairment based on remaining lease terms, drilling results, reservoir performance, future plans to develop acreage, and other relevant factors.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and any gain or loss is recognized. On the sale or retirement of a partial unit of a proved property, a pro-rata portion of the cost and related accumulated depreciation, depletion and amortization are eliminated from the property accounts.

Other Property and Equipment

Other property and equipment, consisting primarily of office, transportation and computer equipment, as well as our new corporate headquarters, is carried at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, ranging from 3 to 5 years, with the exception of our corporate headquarters, which is 30 years. Major renewals and improvements are capitalized, while expenditures for maintenance and repairs are expensed as incurred. Upon sale or abandonment, the cost of the equipment and related accumulated depreciation are removed from the accounts, and any gain or loss is recognized.

Impairment of Long-Lived Assets

The carrying value of long-lived assets and certain identifiable intangibles are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. When it is determined that the estimated future net cash flows of an asset will not be sufficient to recover its carrying amount, an impairment loss must be recorded to reduce the carrying amount to its estimated fair value. Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows and an asset's fair value. These judgments and assumptions include such matters as the estimation of oil and gas reserve quantities, risks associated with the different categories of oil and gas reserves, the timing of development and production, expected future commodity prices, capital expenditures, production costs, and appropriate discount rates.

The Company evaluates impairment of proved and unproved oil and gas properties on a region basis. On this basis, certain regions may be impaired because they are not expected to recover their entire carrying value from future net cash flows. As a result of this evaluation, the Company recorded impairment of unproved oil and gas properties of approximately $12.2 million and $28.6 million for the years ended December 31, 2018 and 2017, respectively, and impairment of proven oil and gas properties of $4.8 million for the year ended December 31, 2017. If pricing declines, it is reasonably likely that the Company may have to record impairment of its oil and gas properties subsequent to December 31, 2018.

Asset Retirement Obligations

Asset retirement obligations are recognized at their fair value at the time that the obligations are incurred. Oil and gas producing companies incur such a liability upon acquiring or drilling a well. Under ASC 410, an asset retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to producing properties in the accompanying consolidated balance sheets, which is allocated to expense over the useful life of the asset. Periodic accretion of the discount on asset retirement obligations is recorded as part of depreciation, depletion and amortization ("DD&A") expense in the accompanying consolidated statement of operations. See Note 7. *Asset Retirement Obligations*, for more information.

Revenue Recognition

Lonestar recognizes revenue at an amount that reflects the consideration to which we expect to be entitles in exchange for transferring goods or services to a customer, using a five-step process, in accordance with ASC 606, *Revenue from Contracts with Customers.* See Note 5. *Revenue Recognition*.

Derivatives

The Company utilizes oil and natural gas derivative contracts to mitigate its exposure to commodity price risk associated with its future oil and natural gas production. These derivative contracts have historically consisted of fixed-price swaps, basis swaps, and collars. We do not apply hedge accounting; accordingly, all derivatives are recorded in the accompanying consolidated balance sheets at estimated fair value. The Company recognizes all changes in the fair values of its derivative contracts as gains or losses in the earnings of the periods in which they occur. See Note 4. *Commodity Price Activities* for more information.

Income Taxes

Lonestar follows the asset and liability method in accounting for income taxes. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, operating losses and tax credit carryforwards.

Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which these temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

The Company periodically evaluates the realizable tax benefits of deferred tax assets and records a valuation allowance, if required, based on an estimate of the amount of deferred tax assets the Company believes does not meet the more likely than not criteria of being realized. In certain circumstances, the deferred tax asset may exceed the amount permissible to be used under the tax law, for example, a net operating loss carryforward. In such cases it is appropriate to write-off the excess net operating loss. See Note 10. *Income Taxes* for more information.

The Company evaluates uncertain tax positions, which requires significant judgments and estimates regarding the recoverability of deferred tax assets, the likelihood of the outcome of examinations of tax positions that may or may not be currently under review, and potential scenarios involving settlements of such matters. Changes in these estimates could materially impact the consolidated financial statements. No liability for material uncertain tax positions existed as of December 31, 2018 or 2017.

Share-Based Payments

Lonestar accounts for equity-based awards in accordance with ASC 718, *Compensation-Stock Compensation,* which requires companies to recognize in the statement of operations all share-based payments granted to employees based on their fair value. Share-based compensation is recognized by the Company on the graded vesting method over the requisite service period, which approximates the option vesting period of three years. Grants that can be settled in either cash or shares are treated as liabilities on the accompanying consolidated balance sheets.

Net Income (Loss) per Common Share

The two-class method is utilized to compute earnings per common share as our Class A Participating Preferred Stock (the "Preferred Stock") is considered a participating security. Under the two-class method, losses are allocated only to those securities that have a contractual obligation to share in the losses of the Company. The Preferred Stock is not obligated to absorb Company losses and accordingly is not allocated losses. Net income attributable to common stockholders is allocated between common stock and participating securities based on the weighted average number of common shares and participating securities outstanding for the period.

Basic earnings per share is computed by dividing the allocated net income (loss) attributable to common stockholders by the weighted-average number of shares of common stock outstanding for the period.

Diluted earnings per share is computed similarly except that the denominator is increased to include dilutive potential common shares. Potential common shares consist of warrants, equity compensation awards and Preferred Stock. In certain circumstances adjustment to the numerator is also required for changes in income or loss resulting from the potential common shares. Basic weighted average common shares exclude shares of non-vested restricted stock. As these restricted shares vest, they will be included in the shares outstanding used to calculate basic earnings per share.

The following is a reconciliation of basic and diluted earnings per share:

In thousands, except shares and per-share data	Year ended December 31, 2018	2017
Numerator - Basic		
Total net income (loss) attributable to common stockholders	$ 11,532	$ (47,453)
Less: allocation to participating securities	(4,270)	—
Net income (loss) attributable to common stockholders - basic	$ 7,262	$ (47,453)
Numerator - Diluted		
Net income (loss) attributable to common stockholders - basic	$ 7,262	$ (47,453)
Unrealized gain on Warrants, net of income tax	(329)	—
Net income (loss) attributable to common stockholders - diluted	$ 6,933	$ (47,453)
Denominator		
Weighted average number of common shares - basic	24,619,730	22,252,149
Warrants converted under the Treasury Stock method	181,413	—
Weighted average number of common shares - diluted	24,801,143	22,252,149
Earnings per share		
Basic	$ 0.29	$ (2.13)
Diluted	$ 0.28	$ (2.13)

The following weighted average securities could potentially dilute earnings per share for the periods indicated, but were excluded from the computation of diluted net income (loss) per share, as their effect would have been antidilutive:

	Year ended December 31, 2018	2017
Preferred stock	14,480,730	7,432,493
Warrants	—	760,000
Stock appreciation rights	922,945	576,986
Restricted stock units	847,542	560,853

2. Recently Issued Accounting Pronouncements

Leases. In February 2016, the FASB issued Accounting Standards Update ("ASU") 2016-02, *Leases* ("ASU 2016-02"). The standard requires lessees to recognize a right of use asset ("ROU asset") and lease liability on the balance sheet for the rights and obligations created by leases. ASU 2016-02 also requires disclosures designed to give financial statement users information on the amount, timing, and uncertainty of cash flows arising from leases. In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842): Targeted Improvements* ("ASU 2018-11"), which provides for an alternative transition method by allowing entities to initially apply the new leases standard at the adoption date, January 1, 2019, and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Comparative periods presented in the financial statements will continue to be in accordance with ASC Topic 840, *Leases*. The standard is effective for annual and interim periods beginning after December 15, 2018, with earlier application permitted.

In the normal course of business, the Company enters into lease agreements to support its exploration and development operations and lease assets, such as drilling rigs, field services and well equipment, office space and other assets. The Company adopted the new standard on the effective date of January 1, 2019, using a modified retrospective approach as permitted under ASU 2018-11.

The new standard provides a number of optional practical expedients in transition. The Company expects to:

- elect the package of 'practical expedients', which permits the Company not to reassess under the new standard its prior conclusions about lease identification, lease classification and initial direct costs;

- elect the practical expedient pertaining to land easements and plan to account for existing land easements under the Company's current accounting policy;

- elect the short-term lease recognition exemption for all leases that qualify and, as such, no ROU asset or lease liability will be recorded on the balance sheet and no transition adjustment will be required for short-term leases; and

- elect the practical expedient to not separate lease and non-lease components for all of the Company's leases.

The Company does not expect to elect the hindsight practical expedient in determining the lease term and assessing impairment of ROU assets when transitioning to ASU 2016-02.

The Company estimates the most significant impact, if any, will relate to the recognition of new ROU assets and lease liabilities on its balance sheet for operating leases, as well as additional disclosures. Consequently, with adoption, the Company expects to recognize additional operating liabilities of less than $1 million with corresponding ROU assets.

Revenue Recognition. Effective January 1, 2018, the Company adopted ASU 2014-09, *Revenue From Contracts with Customers* ("ASU 2014-09"), using the modified retrospective method. Under the modified retrospective method, the Company recognized the cumulative effect of initially applying ASU 2014-09 as an adjustment to the opening balance of accumulated deficit; however, no adjustment was required as a result of adopting the new standard. Results for reporting periods beginning after January 1, 2018 are presented under ASC 606. The comparative information has not been restated and continues to be reported under historic accounting standards in effect for those periods. The impact of the adoption of ASU 2014-09 was, and is expected to be, immaterial to the Company's net income on an ongoing basis. See Note 5. *Revenue Recognition,* for further discussion.

3. Acquisitions and Divestitures

Sooner Acquisition

On November 15, 2018, Lonestar completed the acquisition of oil and gas properties in the Sugarkane Field in DeWitt County, Texas, for $38.7 million, before closing adjustments, from Sabine Oil & Gas Corporation and Alerion Gas AXA, LLC (the "Sooner Acquisition"). The acquisition was financed with funds available from our Credit Facility, as well as cash from operations. The Sooner Acquisition was accounted for as an asset acquisition applying the guidance of ASU 2017-01. As such, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date, and all of the value of the transaction was allocated to proved oil and gas properties. Transaction costs of $0.3 million were capitalized as a component of the cost of the assets acquired.

New Corporate Headquarters

On August 2, 2017, Lonestar closed on the purchase of an office building in Fort Worth, Texas, with an acquisition price approximating $10 million, to which the Company relocated its corporate operations in February 2018. In light of the relocation, the Company recorded an impairment charge of $1.6 million in Other Expense during the first quarter of 2018, primarily reflecting the remaining future minimum rentals of the lease for the Company's prior corporate office from the date of relocation to the end of the remaining lease term.

Battlecat Acquisition

On June 15, 2017, Lonestar closed an acquisition with Battlecat Oil & Gas, LLC ("Battlecat") whereby the Company acquired oil and gas properties in the Eagle Ford Shale play in DeWitt, Gonzales and Karnes County, Texas (the "Battlecat Acquisition"). The total purchase consideration of approximately $59.8 million consisted of $55.0 million in cash and 1,184,632 shares of Series B Convertible Preferred Stock, par value $0.001 per share ("Series B Preferred Stock") at a value of approximately $4.8 million. Allocation of the purchase consideration was as follows: $56.3 million to proved reserves; $2.9 million to unproved reserves and $0.6 million to unevaluated acreage and other assets. Additionally, the Company recorded an asset retirement obligation of approximately $0.2 million, resulting in fair value of net assets acquired of approximately $59.6 million. The Company accounted for the acquisition as a business combination under ASC 805. Acquisition-related costs of approximately $1.5 million were charged to Acquisition Costs in the Consolidated Statements of Operations.

Marquis Acquisition

On June 15, 2017, Lonestar closed an acquisition with SN Marquis LLC (a subsidiary of Sanchez Energy Corporation) ("Marquis") whereby the Company acquired oil and gas properties in the Eagle Ford Shale play in Fayette, Gonzales and Lavaca County, Texas (the "Marquis Acquisition"). The total purchase consideration of approximately $50.0 million consisted of $44.0 million in cash and 1,500,000 shares of Series B Preferred Stock at a value of approximately $6.0 million. Allocation of the purchase price was as follows: $48.0 million to proved reserves; $0.6 to unproved reserves and $1.4 million to land, building and other assets. Additionally, the Company recorded an asset retirement obligation of approximately $1.9 million, resulting in fair value of net assets acquired of approximately $48.1 million. The Company accounted for the acquisition as a business combination under ASC 805. Acquisition-related costs of approximately $1.2 million were charged to Acquisition Costs in the Consolidated Statements of Operations.

4. Commodity Price Risk Activities

Lonestar enters into certain commodity derivative instruments to mitigate commodity price risk associated with a portion of its future oil, NGL and natural gas production and related cash flows. The oil, NGL and natural gas revenues and cash flows are affected by changes in commodity product prices, which are volatile and cannot be accurately predicted. The objective for entering into these commodity derivatives is to protect the operating revenues and cash flows related to a portion of the future oil, NGL and natural gas sales from the risk of significant declines in commodity prices, which helps ensure the Company's ability to fund the capital budget.

Inherent in Lonestar's fixed price contracts are certain business risks, including market risk and credit risk. Market risk is the risk that the price of oil and natural gas will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from non-performance by the Company's counterparty to a contract. The Company does not currently require cash collateral from any of its counterparties nor does its counterparties require cash collateral from the Company. As of December 31, 2018, the Company had no open physical delivery obligations.

The following table summarizes Lonestar's commodity derivative contracts as of December 31, 2018:

Commodity	Contract Type	Period	Range (1)	Volume Hedged (Bbls/Mcf per day)	Weighted Average Price
Oil – WTI	Swaps	Jan - Dec 2019	$48.04 - $69.56	6,000	$ 53.88
Oil – Argus WTI(2)	Basis Swaps	Jan - Dec 2019	5.00 - 5.55	6,000	5.05
Oil – WTI	Swaps	Jan - June 2020	48.90 - 65.56	2,592	55.70
Oil - WTI	Swaps	July - Dec 2020	55.06 - 65.56	2,765	58.15
Natural Gas - Henry Hub	Swaps	Jan - Mar 2019	3.24 - 4.41	15,000	3.78
Natural Gas - Henry Hub	Swaps	Oct - Dec 2019	2.78 - 2.98	15,000	2.87

(1) Ranges presented for fixed-price swaps and basis swaps represent the lowest and highest fixed prices of all open contracts for the period presented.

(2) Basis swap contracts establish a fixed amount for the differential between Argus WTI and Argus LLS prices on a trade-month basis for the period indicated.

During February and March of 2019, the Company entered into additional WTI swaps for 122,500 Bbls at a strike price of $58.72 per Bbl for the period of May through December 2019, and 732,000 Bbls at a weighted average strike price of $57.85 per Bbl for the period of January through December 2020. During February 2019, the Company also entered into additional Henry Hub swaps for the period of January through December 2019 for 2,745,000 Mcf at a weighted average strike price of $2.77 per Mcf.

As of December 31, 2018, all of the Company's derivative hedge positions were with large financial institutions, which are not known to the Company to be in default on their derivative positions. The Company is exposed to credit risk to the extent of non-performance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate non-performance by such counterparties. None of the Company's derivative instruments contain credit-risk related contingent features.

5. Revenue Recognition

Operating revenues are comprised of sales of crude oil, NGLs and natural gas, as presented in the accompanying consolidated statements of operations for the years ended December 31, 2018 and 2017.

Accounting Policies

Revenue is recognized when performance obligations under the terms of a contract with a customer are satisfied. The Company recognizes revenue when control has been transferred to the customer, generally at the time commodities reach an agreed-upon delivery point. Revenue is measured as the amount of consideration the Company expects to receive in exchange for transferring products and is generally based upon a negotiated formula, list or fixed price based on a market index. Typically, the Company sells its products directly to customers generally under agreements with payment terms less than 30 days.

Oil Revenues

The Company's crude oil sales contracts are generally structured such that Lonestar commits and dedicates for sale a specified volume of oil production from agreed-upon leases to a purchaser. Oil is sold at a contractually-specified index price plus or minus a differential, and title and control of the product generally transfers at the delivery point specified in the contract, at which point related revenue is recognized. For those leases in which Lonestar operates with other working interest owners, the Company recognizes oil revenue proportionate to its entitled share of volumes sold. Currently, all of Lonestar's oil production comes from the Eagle Ford play in South Texas, and direct sales to four purchasers account for the majority of its oil sales.

The Company's oil purchase contracts are generally written to provide month-to-month terms with a 30-day cancellation notice. Sales of Lonestar's oil production are typically invoiced monthly based on actual volumes measured at the agreed-upon delivery point and stated contract pricing for the month.

NGLs and Natural Gas Revenues

The Company's NGL and natural gas purchase contracts are generally structured such that Lonestar commits and dedicates for sale a specified volume of NGL and/or natural gas production per day from agreed-upon leases to a purchaser. NGLs and natural gas are sold at a percentage of index prices of each component less any stated deductions. Control transfers at the delivery point specified in the contract, which typically is stated as the inlet or tailgate of a plant where the produced NGLs and natural gas are processed for subsequent transportation and consumption. In certain situations, Lonestar takes processed natural gas in-kind from a processing plant for sale under a separate purchase agreement with a different delivery point. The stated delivery point determines whether certain conditioning, treating, transportation and fractionation fees associated with the sold NGLs and natural gas are treated as operating expenses (occurring before the delivery point) or as deductions to revenues (occurring after the delivery point).

For those leases in which Lonestar operates with other working interest owners, the Company recognizes NGL and natural gas revenue proportionate to its entitled share of volumes sold. Currently, all of Lonestar's NGL and natural gas production comes from the Eagle Ford play in South Texas. Sales of Lonestar's NGL and natural gas production is typically invoiced monthly based on actual volumes at the agreed-upon delivery point and stated contract pricing and allocations for the month.

Lonestar uses a third-party broker for its NGL and natural gas marketing. In this capacity, the third-party is responsible for carrying out marketing activities such as submission of nominations, receipt of payments, submission of invoices and negotiation of contracts. In this agreement, Lonestar retains final approval of contracts and is not entitled to sales proceeds from the third-party until they are collected from the related purchasers. Commissions payable to the third-party broker for these services are treated as operating expenses in the financial statements.

Production Imbalances

Revenue is recorded based on the Company's share of volumes sold, regardless of whether the Company has taken its proportional share of volumes produced. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. There were no imbalances at December 31, 2018.

Significant Judgements

As noted above, the Company engages in various types of transactions in which midstream entities process its gas and subsequently market resulting NGLs and residue gas to third-party customers on Lonestar's behalf. These types of transactions require judgement to determine whether Lonestar is the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

The Company has determined that each unit of product represents a separate performance obligation under the terms of its purchase contracts, and therefore, future volumes are wholly unsatisfied. Therefore, the Company has utilized the practical expedient exempting a Company from disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements for certain NGL and natural gas sales may not be received for 30 to 60 days after the date production is delivered, and as a result, Lonestar is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product.

The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the year ended December 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Accounts Receivable and Other

Accounts receivable – Oil, natural gas liquid and natural gas sales consist of amounts due from purchasers for commodity sales from our Eagle Ford fields. Payments from purchasers are typically due by the last day of the month following the month of delivery. There was no bad debt expense for any period presented, and an allowance for uncollectible accounts is unnecessary. The Company's operations do not result in any contract assets or liabilities on the accompanying consolidated balance sheets.

6. Fair Value Measurements

Fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. ASC 820 prioritizes the inputs used in measuring fair value into the following fair value hierarchy:

- *Level 1* – Quoted prices for identical assets or liabilities in active markets.
- *Level 2* – Quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or

liability, and inputs derived principally from or corroborated by observable market data by correlation or other means.

- *Level 3* – Unobservable inputs for the asset or liability. The fair value input hierarchy level to which an asset or liability measurement falls in its entirety is determined based on the lowest level input that is significant to the measurement in its entirety.

Assets and liabilities measured at fair value on a recurring basis

The following table presents Lonestar's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2018 and 2017, for each fair value hierarchy level:

	Fair Value Measurements Using			
In thousands	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2018				
Assets:				
Commodity derivatives	$ —	$ 23,143	$ —	$ 23,143
Liabilities:				
Commodity derivatives	—	(451)	—	(451)
Warrants	—	—	(1,055)	(1,055)
Stock-based compensation	(1,267)	—	(636)	(1,903)
Total	$ (1,267)	$ 22,692	$ (1,691)	$ 19,734
December 31, 2017				
Assets:				
Commodity derivatives	$ —	$ 472	$ —	$ 472
Liabilities:				
Commodity derivatives	—	(22,138)	—	(22,138)
Warrants	—	—	(1,471)	(1,471)
Stock-based compensation	—	—	(314)	(314)
Total	$ —	$ (21,666)	$ (1,785)	$ (23,451)

Commodity Derivatives

The Company's commodity derivatives represent non-exchange-traded oil and natural gas fixed-price swaps that are based on NYMEX pricing and fixed-price basis swaps that are based on regional pricing other than NYMEX (e.g., Louisiana Light Sweet). The asset and liability measurements for the Company's commodity derivative contracts represent Level 2 inputs in the hierarchy, as they are valued based on observable inputs other than quoted prices.

Warrants

The fair value of the Company's warrants is based on Black-Scholes valuations. In addition to the Company's observable stock price, other significant inputs are considered unobservable, and the Company has designated these estimates as Level 3.

Stock-Based Compensation

The Company's stock-based compensation includes the liability associated with restricted stock units ("RSUs") and stock appreciation rights ("SARs") dependent on the fair value of Lonestar's publicly-traded common stock. The fair value of RSUs is measured based on measurable prices on a major exchange; the significant inputs to these asset exchange values represented Level 1 independent active exchange market price inputs. The Black-Scholes model used to determine the fair value of the SARs uses inputs, in addition to the Company's observable stock price, that are considered unobservable; to this end the Company has designated these estimates as Level 3. See Note 12. *Stock-Based Compensation*, below for more information.

Level 3 gains and losses

The table below sets forth a summary of changes in the fair value of the Company's Level 3 liabilities for the year ended December 31, 2018.

In thousands	Warrant	Stock-Based Compensation	Total
Balance at December 31, 2017	$ (1,471)	$ (314)	$ (1,785)
Unrealized gains (losses)	416	(322)	94
Balance at December 31, 2018	$ (1,055)	$ (636)	$ (1,691)

Assets and liabilities measured at fair value on a nonrecurring basis

Non-recurring fair value measurements include certain non-financial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and natural gas property assessments; warrants issued in debt or equity offerings and the initial recognition of asset retirement obligations for which fair value is used. These estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these estimates as Level 3.

Other fair value measurements

The book values of cash and cash equivalents, accounts receivable and accounts payable, approximate fair value due to the short-term nature of these instruments. The carrying value of debt approximates fair value since it is subject to a short-term floating interest rate that approximates the rate available to the Company, except for bonds, which are recorded at amortized cost less debt issuance costs. The fair value of the 11.25% Senior Notes (as defined in Note 9. below) was approximately $234 million as of December 31, 2018, and are considered a Level 3 liability, as they are based on market transactions that occur infrequently as well as internally generated inputs.

7. Asset Retirement Obligations

Lonestar recognizes the fair value of its asset retirement obligations related to the plugging, abandonment, and remediation of oil and gas producing properties. The present value of the estimated asset retirement costs has been capitalized as part of the carrying amount of the related long-lived assets.

The liability has been accreted to its present value as of December 31, 2018. The Company evaluated its wells and has determined a range of abandonment dates through December 2070.

The following provides a reconciliation of activity in the asset retirement obligations for the years ended December 31, 2018 and 2017:

	Year Ended December 31,	
In thousands	2018	2017
Beginning asset retirement obligations	$ 5,649	$ 2,683
Wells drilled during the year	408	220
Wells acquired during the year	223	2,797
Accretion expense	215	139
Revisions in estimated retirement obligations[1]	790	(190)
Wells plugged and abandoned during the year	(90)	—
Ending asset retirement obligations	$ 7,195	$ 5,649

(1) Revisions of previous estimates during the year ended December 31, 2018 are primarily attributable to changes in estimates of the amount of future costs for oilfield services required to plug and abandon wells.

8. Accrued Liabilities

The following table provides detail of Lonestar's accrued liabilities as of December 31, 2018 and 2017:

	December 31,	
In thousands	2018	2017
Bonus payable	$ 3,244	$ 2,250
Payroll payable	773	18
Accrued interest - 8.75% Senior Notes	—	2,768
Accrued interest - 11.25% Senior Notes	14,063	—
Accrued interest - other	104	1,015
Accrued rent	105	156
Accrued well costs	9,026	8,386
Accrued severance, property and franchise taxes	96	115
Accrued federal income tax	441	1,147
Other	276	728
Total accrued liabilities	$ 28,128	$ 16,583

9. Long-Term Debt

The following long-term debt obligations were outstanding as of December 31, 2018 and 2017:

In thousands	December 31, 2018	December 31, 2017
Senior Secured Credit Facility	$ 183,000	$ 142,080
8.75% Senior Notes due 2019	—	151,848
11.25% Senior Notes due 2023	250,000	—
Mortgage debt	9,151	7,891
Other	275	759
Total long-term debt	442,426	302,578
Unamortized discount	(4,500)	(949)
Unamortized debt issuance costs	(1,044)	(474)
Total long-term debt net of discount and debt issuance costs	$ 436,882	$ 301,155

Senior Secured Credit Facility

On July 28, 2015, Lonestar closed a Credit Agreement for a $500 million Senior Secured Credit Facility with Citibank, N.A., as administrative agent, and other lenders party thereto (as amended, supplemented or modified from time to time, the "Credit Facility"). The Credit Facility has a maturity date of November 15, 2023. As of December 31, 2018 and 2017, $183.0 million and $142.1 million was borrowed, respectively, under the Credit Facility. Borrowing availability was $91.5 million as of December 31, 2018, which reflects $0.5 million of letters of credit outstanding.

The Credit Facility may be used for loans and, subject to a $2.5 million sub-limit, letters of credit, and provides for a commitment fee of 0.375% to 0.5% based on the unused portion of the borrowing base under the Credit Facility. As of December 31, 2018, the borrowing base and lender commitments for the Credit Facility was $275.0 million. The borrowing base under the Credit Facility is determined semi-annually as of May 1 and November 1.

Borrowings under the Credit Facility, at Lonestar's election, bear interest at either: (i) an alternate base rate ("ABR") equal to the higher of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5% per annum, and (c) the adjusted LIBO rate of a three-month interest period on such day plus 1.0%; or (ii) the adjusted LIBO rate, which is the rate stated on Reuters screen LIBOR1 page, for one, two, three, six or twelve months, as adjusted for statutory reserve requirements for Eurocurrency liabilities, plus, in each of the cases described in clauses (i) and (ii) above, an applicable margin ranging from 1.50% to 2.50% for ABR loans and from 2.50% to 3.50% for adjusted LIBO rate loans). The weighted average interest rate on borrowings under the Credit Facility was 5.13% for the year ended December 31, 2018.

Subject to certain permitted liens, the Company's obligations under the Credit Facility have been secured by the grant of a first priority lien on no less than 80% of the value of the proved oil and gas properties of the Company and its subsidiaries (currently 90%).

The Credit Facility contains certain financial performance covenants, as defined in the Credit Facility, including the following:

- A maximum debt to EBITDAX ratio of 4.0 to 1.0, and
- A current ratio of not less than 1.0 to 1.0.

The Company was in compliance with the terms of the Credit Facility as of December 31, 2018.

Sixth Amendment

In connection with closing the Marquis Acquisition and the Battlecat Acquisition, in June 2017, Lonestar entered into the Sixth Amendment and Joinder to Credit Agreement (the "Sixth Amendment") to (i) increase the borrowing base from $112 million to $160 million, (ii) modify the maximum leverage ratio threshold to be 4.0 to 1.0 for all periods, starting with the fiscal quarter ending September 30, 2017, and providing that EBITDAX (as defined in the Credit Facility) shall be calculated at the end of each fiscal quarter using the results of the twelve-month period ending with that fiscal quarter end; provided, that EBITDAX shall be calculated (x) at the end of the fiscal quarter ending September 30, 2017 using an amount equal to the EBITDAX for such fiscal quarter, multiplied by four, (y) at the end of the fiscal quarter ending December 31 ,2017 using an amount equal to the EBITDAX for the two fiscal quarter period ended on such date, multiplied by two and (z) at the end of the fiscal quarter ending March 31, 2018 using an amount equal to the EBITDAX for the three fiscal quarter period ended on such date, multiplied by four-thirds, (iii) permit the Company to declare and pay dividends equal to the amount of any cash dividends declared and payable in accordance with the terms of the Company's Certificate of Designations of Convertible Participating Preferred Stock, Series A-1, and Certificate of Designations of Convertible Participating Preferred Stock, Series A-2, subject to certain specified terms and conditions and (iv) amend certain other provisions of the Credit Facility.

Seventh Amendment

In January 2018, the Company entered into the Limited Waiver, Borrowing Base Redetermination Agreement, and Amendment No. 7 to the Credit Agreement (the "Seventh Amendment"), which (i) maintained the borrowing base of $160 million until the next redetermination date; (ii) waived the borrowing base redetermination that would otherwise have occurred in connection with the incurrence of the 11.25% Senior Notes (see below), and (iii) amended certain other provisions of the Credit Facility, as set forth more specifically in the Seventh Amendment.

Eighth Amendment

In May 2018, the Company entered into the Borrowing Base Redetermination Agreement and Amendment No. 8 to Credit Agreement (the "Eighth Amendment"), which (i) increased the borrowing base from $160 million to $190 million and (ii) reallocated the commitments and outstanding loans among lenders, as set forth more specifically in the Eighth Amendment.

Ninth Amendment

In November 2018, the Company entered into the Ninth Amendment and Joinder (the "Ninth Amendment"), which (i) increased the borrowing base from $190 million to $275 million; (ii) extended the maturity date of the Credit Facility to November 15, 2023, and (iii) amended certain other provisions of the Credit Facility, as set forth more specifically in the Ninth Amendment.

11.25% Senior Notes

In January 2018, the Company issued $250.0 million of 11.250% Senior Unsecured Notes due 2023 (the "11.25% Senior Notes") to U.S.-based institutional investors. The net proceeds of $244.4 million were used to fully retire the 8.75% Senior Notes (as defined below), which included principal, interest and a prepayment premium totaling approximately $162.0 million. The remaining net proceeds were used to reduce borrowings under the Credit Facility.

The 11.25% Senior Notes mature on January 1, 2023, and bear interest at the rate of 11.25% per year, payable on January 1 and July 1 of each year, beginning July 1, 2018. At any time prior to January 1, 2021, the Company may, on any one or more occasions, redeem up to 35% of the aggregate principal amount of the 11.25% Senior Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 111.25% of the principal amounts redeemed, plus accrued and unpaid interest, provided that at least 65% of the aggregate principal amount of 11.25% Senior Notes originally issued remains outstanding immediately after such redemption and the redemption occurs within 180 days of the closing date of such equity offering.

At any time prior to January 1, 2021, the Company may, on any one or more occasions, redeem all or a part of the 11.25% Senior Notes at a redemption price equal to 100% of the principal amount redeemed, plus a "make-whole" premium and accrued and unpaid interest.

On and after January 1, 2021, the Company may redeem the 11.25% Senior Notes, in whole or in part, plus accrued and unpaid interest, at the following redemption prices: 108.438% after January 1, 2021; 105.625% after January 1, 2022; and 100% after July 1, 2022.

The indenture contains certain restrictions on the Company's ability to incur additional debt, pay dividends on the Company's common stock, make investments, create liens on the Company's assets, engage in transactions with affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of the Company's assets.

8.75% Senior Notes

On April 4, 2014, Lonestar issued, at par, $220.0 million of 8.750% Senior Unsecured Notes due April 15, 2019 (the "8.75% Senior Notes") to U.S.-based institutional investors.

Using proceeds from the issuance of the 11.25% Senior Notes, the Company fully retired the 8.75% Senior Notes in January 2018. Pursuant to the terms of the indenture noted above, the 8.75% Senior Notes were redeemed at 104.375% of the outstanding principal amount, or approximately $158.5 million, which excluded accrued interest. In connection with this transaction, the Company recognized an $8.6 million loss on extinguishment during the first quarter of 2018.

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt and amortizes such costs over the lives of the respective debt. At December 31, 2018 and 2017, the Company had approximately $1.7 million and $2.3 million, respectively, of debt issuance costs associated with issuance of the Credit Facility remaining that are being amortized over the lives of the respective debt which are recorded as Other Non-Current Assets in the accompanying consolidated balance sheets.

Securities Purchase Agreement and Second Lien Notes

On August 2, 2016, Lonestar entered into a Securities Purchase Agreement with Juneau Energy, LLC, as initial purchaser ("Juneau"), Leucadia National Corporation ("Leucadia"), as guarantor of Juneau's obligations, the other purchasers party thereto and Jefferies, LLC, in its capacity as the collateral agent for the purchasers, relating to the issuance and sale of (i) up to $49.9 million aggregate principal amount of the Company's 12% Senior Secured Second Lien Notes due 2021 (the "Second Lien Notes") and (ii) five-year warrants to purchase up to an aggregate 998,000 shares of the Company's Class A voting common stock at a price equal to $5.00 per share (the "Warrants"). The balance of the warrants is reflected in Equity Warrant Liability – Related Parties on the accompanying consolidated balance sheets. The Second Lien Notes were secured by second-priority liens on substantially all of the Company and its subsidiaries' assets to the extent such assets secure obligations under the Credit Facility.

During 2016, the Company issued $38.0 million in aggregate principal amount of Second Lien Notes and issued Warrants to purchase 760,000 shares of its Class A voting common stock. The Company recorded an equity warrant liability of approximately $5.1 million which was the fair value amount at the date of issuance. The Warrants were adjusted to fair value at December 31, 2018 which resulted in a gain on the Warrants of approximately $0.4 million for the year ended December 31, 2018, which is recorded in the accompanying consolidated statements of operations. Proceeds from the Second Lien Notes issuance were used to repurchase approximately $68.2 million in aggregate principal amount of the 8.75% Senior Notes in privately negotiated open market repurchases with holders of such notes, and to pay related fees and expenses related to the foregoing. The repurchase amounts paid were approximately $36.2 million in cash.

In December 2016, the Company repaid $21.0 million principal of the Second Lien Notes with proceeds from the offering of the Company's Class A voting common stock (the "2016 Common Stock Offering").

In June 2017, the Company repaid the remaining $17.0 million principal of the Second Lien Notes including an early payment premium of approximately $1.1 million with borrowings from the Credit Facility.

As of December 31, 2018, our debt is payable over the next five years and thereafter as follows:

In thousands		
2019	$	62
2020		66
2021		71
2022		76
2023		433,006
Thereafter		9,145
Total debt	$	442,426

10. Income Taxes

The income tax provision is as follows:

In thousands	Year Ended December 31, 2018	2017
Current income tax (benefit) expense		
Federal	$ (1,100)	$ 59
State	291	113
Total current income tax (benefit) expense	(809)	172
Deferred tax expense (benefit)		
Federal	7,686	(29,125)
State	(85)	(66)
Total deferred income tax expense (benefit)	7,601	(29,191)
Total income tax expense (benefit)	$ 6,792	$ (29,019)

The following table provides a reconciliation of Lonestar's actual income tax provision amounts from the expected income tax provision amount by applying the U.S. federal statutory corporate income tax rate of 21% and 35% for the years ended December 31, 2018 and 2017, respectively:

In thousands	Year Ended December 31, 2018	2017
Expected income tax expense (benefit) at statutory rate	$ 5,489	$ (25,370)
Permanent differences	123	(357)
Adjustment to NOL	1,119	—
Remeasurement of deferred balances due to federal rate change	—	(4,140)
State tax, tax effected	146	97
Prior year differences	(210)	779
Stock-based compensation differences	112	—
Other	13	(28)
Actual income tax expense (benefit)	$ 6,792	$ (29,019)

Significant components of the Company's deferred tax assets and liabilities as of December 31, 2018 and 2017 are as follows:

In thousands	December 31, 2018	2017
Deferred tax assets		
Net operating loss carryforward	$ 17,765	$ 20,874
Stock-based compensation	1,973	1,891
Intangibles	304	351
Derivative instruments	—	4,429
Interest expense limitation	2,254	—
Organizational expenses and other	4,477	2,900
Total deferred tax assets	$ 26,773	$ 30,445
Deferred tax liabilities		
Oil and gas properties, and other property and equipment, principally due to intangible drilling costs	$ (34,332)	$ (35,214)
Derivative instruments	(4,811)	—
Net deferred tax liabilities	$ (12,370)	$ (4,769)

The net operating loss carryforward as of December 31, 2018, approximates $84.6 million and begins to expire in 2030 with the exception $0.8 million related to fiscal year 2018, which has no expiration.

On December 22, 2016, the Company completed a public offering of 13.8 million of its Class A common stock. A change of ownership, as defined under the provisions of Section 382 of the Internal Revenue Code ("IRC") occurred on this date. A portion of our net operating loss and tax credit carryforwards will be limited in future periods. IRC Section 382 places limitations on the amount of taxable income which may be offset by tax carryforward attributes, such as net operating losses or tax credits after a change of ownership event. As a result of this ownership change, certain of our accumulated net operating losses will be subject to an annual limitation regarding their utilization against taxable income in future periods. The 2016 change creates an estimated annual utilization limit of approximately $1.0 million on our ability to utilize net operating losses generated prior to the ownership change event. Built-in gains associated with our deferred tax attributes on the date of the ownership change may increase the net operating loss utilization limit in future periods, allowing additional utilization of net operating losses generated prior to the date of the ownership change. Due to the ownership change and the resulting limitation on the utilization of net operating loss generated prior to the change, an estimated $141.7 million of the net operating loss carryforwards were written off in 2016. As of December 31, 2018, the Company has approximately $8.7 million of percentage depletion carryover which has no expiration.

On June 15, 2017, the Company entered into an amended and restated purchase agreement with Chambers Energy Capital III, LP ("Chambers") where the Company closed transactions issuing Chambers 5,400 shares of Series A-1 Preferred Stock and 74,600 shares of Series A-2 Preferred Stock. These transactions created an additional change of ownership under the provision of Section 382 of the IRC. The 2017 change creates an additional estimated annual utilization limit of approximately $0.8 million on our ability to utilize net operating losses generated subsequent to the 2016 change in ownership, but prior to the June, 2017 change in ownership.

If the Company were to experience another ownership change in future periods, the net operating loss carryforwards may be subject to additional utilization limits.

The Company files income tax returns in the United States federal jurisdiction and in various state jurisdictions. As of December 31, 2018, there is one current examination of federal or state jurisdictions in progress. The Company's income tax returns related to fiscal years ended December 31, 2010 through 2018 remain open to possible examination by the tax authorities. The Company has not recorded any interest or penalties associated with uncertain tax positions.

Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse. As a result of the reduction in the U.S. corporate income tax rate from 35% to 21% under the Tax Cuts and Jobs Act (the "Act"), the Company revalued its deferred tax assets and liabilities at December 31, 2017, which resulted in a $4.1 million benefit.

The corporate alternative minimum tax ("AMT") for tax years beginning in January 1, 2018 has also been repealed. The Act provides that existing AMT credit carryovers are refundable beginning in 2018. As of December 31, 2018, the Company had AMT credit carryovers of $1.2 million that are expected to be fully refunded by 2022.

The deductibility of interest expense for tax years beginning in January 1, 2018 has been limited to 30% of earnings before interest, taxes, depreciation, and amortization for the four years ending 2021. Deductibility of interest expense for tax years beginning in January 1, 2022 will then be limited to 30% of earnings before interest and taxes thereafter. For the year ended December 31, 2018, our deductible interest expense was limited to $25.5 million, which resulted in a $2.3 million deferred tax asset.

11. Stockholders' Equity

Series A & B Preferred Stock

In June 2017, in connection with financing the Battlecat and Marquis Acquisitions, the Company issued 5,400 shares of Series A-1 Convertible Participating Preferred Stock, par value $0.001 per share (the "Series A-1 Preferred Stock") and 74,600 shares of Series A-2 Convertible Participating Preferred Stock, par value $0.001 per share (the "Series A-2 Preferred Stock" and, together with the Series A-1 Preferred Stock, the "Series A Preferred Stock"), to Chambers Energy Capital ("Chambers"). Also in June 2017, in connection with the Battlecat and Marquis Acquisitions, the Company issued 1,184,632 and 1,500,000 shares of Series B Preferred Stock to Battlecat and Marquis, respectively (see Note 3, Acquisitions and Divestitures).

As a result of the stockholder approval obtained in November 2017, all outstanding Series A-2 Preferred Stock was converted to Series A-1 Preferred Stock. Also, on November 3, 2017, in accordance with the terms of the Series B Certificate of Designations, all of the outstanding shares of the Company's Series B Preferred Stock were converted on a one-for-one basis into shares of the Company's Class A voting common stock.

After the Chambers agreement closing, and for so long as the Approved Holders (as defined) beneficially own at least 10% of the total number of outstanding shares of Class A voting common stock and Class B non-voting common stock (collectively, "Common Stock") of the Company, on an as-converted basis, or at least 15% of the number of Series A Preferred Stock issued to Chambers, the Company cannot undertake certain actions without the prior consent of holders of a majority of all shares of Common Stock, on an as-converted basis, held by the Approved Holders. Prior to June 15, 2020, Chambers and its affiliates are prohibited from directly or indirectly engaging in any short sales involving the Common Stock or securities convertible into, or exercisable or exchanged for, Common Stock. Without the prior written consent of the board, the Approved Holders are subject to customary standstill restrictions until the earlier of (i) the two-year anniversary of the date the Approved Holders are no longer entitled to designate any director to the Board and (ii) the date the Company fails to fully declare and pay all accrued dividends on either series of the Series A Preferred Stock after there are no PIK Quarters (as defined below) remaining. In connection with the closing and the issuance of shares of Series A Preferred Stock, the Company entered into a registration rights agreement with Chambers (the "Chambers RRA"). Under the Chambers RRA, the Company has agreed to provide to Chambers certain customary demand and piggyback registration rights relating to Chambers' ownership of Company stock. The Chambers RRA contains customary terms and conditions, including certain customary indemnification obligations.

The Series A-1 Preferred Stock ranks senior to Class A voting common stock with respect to dividend rights and rights upon the liquidation, winding-up or dissolution of the Company, and the series initially has a stated value of $1,000 per share. Holders of Series A-1 Preferred Stock are entitled to vote with holders of Class A voting common stock on an as-converted basis. Shares of Series A-1 Preferred Stock are convertible into shares of Class A voting common stock at the option of the holders of such Series A-1 Preferred Stock at a per share rate (the "Conversion Rate") equal to the Stated Value of such share divided by six, subject to certain adjustments (the "Conversion Price"). The Company has the option to convert Series A-1 Preferred Stock to Class A voting common stock if the volume weighted average price of Class A voting common stock exceeds the following percentages of the Conversion Price for twenty out of thirty consecutive trading days: (i) 200%, if such mandatory conversion occurs prior to June 15, 2019, (ii) 175%, if such mandatory conversion occurs after June 15, 2019 but before June 15, 2020, and (iii) 150%, if such mandatory conversion occurs after June 15, 2020.

Holders of Series A Preferred Stock are entitled to cumulative dividends payable quarterly initially at a rate of 9% per annum (the "Dividend Rate") in cash and, for any 12 quarters ("PIK Quarters"), at the Company's option, (i) in the form of additional shares of the respective series of Series A Preferred Stock at a per share price equal to $975 or (ii) by increasing Stated Value, in lieu of cash (collectively, the "PIK Option"). After the 12 PIK Quarters (six of which remain as of December 31, 2018), if the Company fails to fully declare and pay dividends in cash, then the Dividend Rate for Series A Preferred Stock will automatically increase by 5.0% per annum for the next succeeding dividend period and then an additional 1.0% for each successive dividend period, up to a maximum Dividend Rate of 20.0% per annum, until the Company pays dividends at such increased rate fully in cash for two consecutive quarters. In addition to dividends rights described above, holders of the Series A Preferred Stock are entitled to receive dividends or distributions declared or paid on Class A voting common stock on an as-converted basis. If on June 15, 2024, the Prevailing Price is less than the Conversion Price then in effect, the Dividend Rate for Series A-1 Preferred Stock will automatically increase to 20.0% per annum, payable only in cash, unless automatically converted as described above. However, the Company, at its option, may instead elect to exchange each share of Series A-1 Preferred Stock for senior unsecured notes of the Company with a two-year maturity, a 9.0% per annum coupon payable semi-annually in cash, and governed by terms substantially similar to the Company's most recent high yield indenture at that time. After June 15, 2020, the Company may redeem shares of Series A Preferred Stock in cash at a per share amount equal to (i) 110% of the Stated Value, if the redemption occurs prior to June 15, 2021, (ii) 105% of the Stated Value, if the redemption occurs on or prior to June 15, 2022, and (iii) 100% of the Stated Value, if the redemption occurs after June 15, 2022, in each case, plus any unpaid dividends.

For the third and fourth quarters of 2017, the Company elected the PIK Option for the Class A Preferred Stock dividend payment, which resulted in the issuance of 1,991 additional shares of Series A-1 Preferred Stock and 1,977 additional shares of Series A-2 Preferred Stock, which were subsequently converted to shares of Series A-1 Preferred Stock during the fourth quarter of 2017.

For the four quarters of 2018, the Company also elected the PIK Option for the Class A Preferred Stock dividend payment, which resulted in the issuance of 7,816 additional shares of Series A-1 Preferred Stock during the year ended December 31, 2018.

Common Stock Issuances

In November 2017, as described above, the Company issued 2,684,632 shares of Class A voting common stock on a one-for-one basis in exchange for all of the of the Company's outstanding Series B Preferred Stock.

Repurchase and Retirement of Class B Common Stock

In connection with the EF Realisation liquidation in October 2018 (see Note 13. *Related Party Activities*), the Company repurchased and retired 2,500 shares of the Class B non-voting common stock (the "Class B Stock") from Dr. Christopher Rowland at a cost of $10,000 in September 2018. The Class B Stock was originally issued to Dr. Rowland in connection with the Company's reorganization in 2016. After the repurchase and retirement of the Class B Stock, there are no shares of Class B Stock issued and outstanding.

12. Stock-Based Compensation

Restricted Stock Units

Lonestar grants awards of restricted stock units ("RSUs") to employees and directors as part of its long-term compensation program. The awards vest over a three-year period, with specific terms of vesting determined at the time of grant. The Company determined the fair value of granted RSUs based on the market price of the Class A voting common stock of the Company on the date of grant. RSUs are paid in Class A voting common stock or cash (see below) after the vesting of the applicable RSU. Compensation expense for granted RSUs is recognized over the vesting period. For the years ended December 31, 2018 and 2017, the Company recognized $1.6 million and $1.3 million, respectively, of stock-based compensation expense for RSUs.

During the first quarter of 2018, the Company elected to offer cash settlement to all employees for vested RSUs and, as a result of this modification, the RSU awards are classified as a liability on the Company's balance sheet in accordance with ASC 718, *Compensation – Stock Compensation,* as of December 31, 2018. As of the date of the modification, periodic compensation expense related to the awards is recognized based on the fair value of the awards, subject to a floor valuation that represents the compensation expense amount that would have otherwise been recognized had the Company not modified the terms of the award. The liability for RSUs on the accompanying consolidated balance sheet as of December 31, 2018 was $1.3 million.

As of December 31, 2018, there was $2.4 million of unrecognized compensation expense related to non-vested RSU grants. This unrecognized compensation cost is expected to be recognized over a weighted-average period of 1.8 years. The fair value of RSU grants that vested during 2018 and 2017 totaled $1.3 million and $0, respectively.

A summary of the status of the Company's non-vested RSU grants issued, and the changes during the year ended December 31, 2018, is presented below:

	Shares	Weighted Average Fair Value per Share
Outstanding non-vested RSUs at December 31, 2017	728,909	$ 5.56
Granted	610,000	4.47
Vested	(295,563)	—
Forfeited	(32,300)	—
Outstanding non-vested RSUs at December 31, 2018	1,011,046	$ 5.06

Stock Appreciation Rights

Lonestar grants awards of stock appreciation rights ("SARs") to employees and directors as part its long-term compensation program. The awards vest over a three-year period, with specific terms of vesting determined at the time of grant, and expire five-years after the date of issuance. The SARs are granted with a strike price equal to the fair market value at the time of grant, which is generally defined as the closing price of the Company's common stock on the NASDAQ on the date of grant. SARs will be paid in cash or common stock at holder's election once the SAR is vested. For the years ended December 31, 2018 and 2017, the Company recognized $0.3 million and $0.3 million, respectively, of stock-based compensation expense for SARs. The liability for SARs on the accompanying consolidated balance sheet as of December 31, 2018 was approximately $0.6 million.

As of December 31, 2018, there was $1.3 million of total compensation cost to be recognized in future periods related to non-vested SAR grants. The cost is expected to be recognized over a weighted-average period of 3.5 years.

The following is a summary of the Company's SAR activity:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (in years)
Outstanding at December 31, 2017	690,000	7.20	4.3
SARs vested and exercisable at December 31, 2017	—	—	—
Granted	335,000	$ 4.46	4.3
Exercised	—	—	—
Expired	—	—	—
Forfeited	(15,000)	—	—
Outstanding at December 31, 2018	1,010,000	$ 6.30	3.5
SARs vested and exercisable at December 31, 2018	280,000	$ 7.20	3.2

13. Related Party Activities

Leucadia

In August 2016, Lonestar entered into a Securities Purchase Agreement (the “Purchase Agreement”) with Juneau, as initial purchaser, Leucadia as guarantor of Juneau’s obligations, the other purchasers party thereto and Jefferies, LLC, in its capacity as the collateral agent for the purchasers, relating to the issuance and sale of (i) up to $49.9 million aggregate principal amount of LRAI’s 12% senior secured second lien notes due 2021 (“Second Lien Notes”) and (ii) five-year warrants to purchase up to an aggregate 998,000 shares of the Company’s Class A voting common stock at a price equal to $5.00 per share (the “Warrants”). During 2016, LRAI issued $25.0 million in aggregate principal amount of Second Lien Notes and the Company issued Warrants to purchase 500,000 shares of its Class A voting common stock to Juneau. In December 2016, LRAI repaid to Juneau $21.0 million principal of the Second Lien Notes.

In connection with entering into the Purchase Agreement, the Company also entered into a registration rights agreement and an equity commitment agreement. Pursuant to the registration rights agreement, the Company had agreed to register for resale certain Class A voting common stock issued or issuable to Juneau and Leucadia, including those issuable upon exercise of the Warrants. The Form S-3 registration statement was filed with the Securities and Exchange Commission on November 7, 2017 and is effective. Leucadia agreed, pursuant to the equity commitment agreement, to purchase a certain number of Class A voting common stock in case the Company elected to pursue an equity offering prior to December 31, 2016. Pursuant to the equity commitment agreement, Leucadia purchased 3,478,261 shares of Class A voting common stock (costing $20 million) through a common stock offering, which closed in December 2016. In connection with Leucadia’s equity commitment, the Company paid Leucadia in January 2017 a $1.0 million fee, which was recorded as a reduction to additional paid-in capital. In the event Leucadia purchased not less than its commitment amount, the Company agreed to use commercially reasonable efforts to enter into arrangements to provide Leucadia with the right to appoint one director to the Board of the Company, provided that such right will terminate at such time as Leucadia and its affiliates own a number of shares of Class A voting common stock equal to less than 50% of the shares purchased by Leucadia and its affiliates in such offering. Leucadia has elected to take an observer position on the board of directors, with no voting rights.

EF Realisation

In October 2016, Lonestar entered into a Board Representation Agreement (the “Board Representation Agreement”) with EF Realisation Company Limited (“EF Realisation”). Under the Board Representation Agreement, for as long as EF Realisation, together with its affiliates, beneficially owns 15% or more of the issued and outstanding shares of the Company’s Class A voting common stock, it has the right to nominate up to, but no more than, two directors to serve on the Board and for as long as EF Realisation, together with its affiliates, beneficially owns at least 10% but less than 15% of the Company’s issued and outstanding shares of Class A voting common stock, it has the right to nominate up to, but no more than, one director to serve on the Board.

On October 9, 2018, EF Realisation notified the Company that it had completed a voluntary liquidation and distribution of assets to certain of its shareholders, including the sale or distribution of all of EF Realisation's 4,174,259 shares of the Company's Class A Stock, representing approximately 17% of the Company's total Class A Stock outstanding at the time. Following the liquidation, EF Realisation is no longer a shareholder of the Company.

Amendment of Registration Rights Agreement

In connection with the Battlecat and Marquis acquisitions, in June 2017, Lonestar entered into (i) a first amendment to the registration rights agreement (the “Leucadia RRA Amendment”) with Leucadia and JETX Energy, LLC (f/k/a Juneau Energy, LLC), which amends the registration rights agreement by and among the same parties, and (ii) a first amendment to registration rights agreement (the “EF RRA Amendment” and, together with the Leucadia RRA Amendment, the “RRA Amendments”) with EF Realisation, which amends the registration rights agreement from October 2016 by and between the same parties. The RRA Amendments set forth the relative priorities, with respect to demand and piggyback registration rights, among each applicable party thereto, Battlecat, Marquis and Chambers under their respective registration rights agreements with the Company.

Other Related Party Transactions

New Tech Global Ventures, LLC, and New Tech Global Environmental, LLC, companies in which a director of the Company owns a limited partnership interest, have provided field engineering staff and consultancy services for the Company since 2013. The total cost for such services was approximately $1.8 million and $1.0 million for the years ended December 31, 2018 and 2017, respectively.

In February 2019, the Company purchased a property adjacent to its corporate office for future expansion for approximately $2.0 million. The transaction was funded with cash from operations. The seller of the property is indebted to certain trusts established in favor of the children of one of the Company's directors. The Company understands that the seller may use some of the proceeds of the sale to satisfy such outstanding indebtedness, though the Company has no interest or influence over any particular outcome.

14. Commitments and Contingencies

Litigation

Lonestar is subject to certain claims and litigation arising in the normal course of business. In the opinion of management, the outcome of such matters will not have a materially adverse effect on the consolidated results of operations or financial position of the Company.

Environmental Remediation

Various federal, state, and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect the Company’s operations and the costs of its oil and gas exploration, development, and production operations. The Company does not anticipate that it will be required in the near future to expend significant amounts in relation to the consolidated financial statements taken as a whole by reason of environmental laws and regulations, and appropriately no reserves have been recorded.

Office Lease

The Company entered into an operating lease agreement for its former corporate office in October 2014 which will expire in October 2021. Future minimum annual lease payments are as follows:

In thousands	Future Minimum Payments
2019	$ 422
2020	432
2021	368
Total minimum lease payments	$ 1,222

Rent payments associated with this property were approximately $412 thousand and $439 thousand for the years ended December 31, 2018 and 2017, respectively. The Company relocated its corporate office to an owned building in February 2018 but will continue to be responsible for the minimum annual lease payments noted above regardless of subrental income, if any, the Company will receive from the property going forward. See Note 3. *Acquisitions and Divestitures* for more information.

Significant Contracts

Lonestar currently has two drilling rigs under contract, each of which provides for a drilling rate of $22.5 thousand per day. The first rig contract commenced in January 2019 and terminates in July 2019 with an early termination fee of $7.0 thousand per day times the remaining number of days left on the contract after the termination date. The second rig contract is an evergreen contract that requires a 30-days cancellation notice with no early termination fees.

In November 2018, the Company signed a dedicated fleet contract that provides for hydraulic fracturing and wireline services at variable rates depending on the work performed. The contract provides for services to cover fourteen wells planned to be drilled during 2019 and expires on December 31, 2019 with no further provisions for early termination. The Company has the ability to further extend the contract on any additional wells added to the 2019 drilling schedule through the expiration date of the contract.

15. Subsequent Events

In February 2019, Lonestar agreed to sell its Pirate assets in Wilson County for $12.3 million, subject to a due diligence period. The sale is anticipated to close prior to the end of March 2019. In February, 2019, average daily sales volumes for the property were 219 BOE/d, and the net book value of the property, as of December 31, 2018, was $45.7 million.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES (UNAUDITED)

Capitalized Costs

The following table presents Lonestar's aggregate capitalized costs relating to oil and gas activities as of December 31, 2018 and 2017:

In thousands	December 31, 2018	December 31, 2017
Oil and natural gas properties:		
Proved properties and equipment	$ 954,083	$ 742,073
Unproved properties	81,850	81,511
Capitalized asset retirement cost	6,627	5,297
Less:		
Accumulated depletion and amortization	(308,043)	(239,297)
Property impairment	(59,258)	(33,413)
Total	$ 675,259	$ 556,171

Costs Incurred

The following table summarizes costs incurred in oil and natural gas property acquisition, exploration and development activities. Property acquisition costs are those costs incurred to purchase, lease or otherwise acquire property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs, and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling development wells, and to provide facilities for extracting, treating, gathering and storing the oil and natural gas.

Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement costs included in the table below were $1.3 million during the year ended December 31, 2018 and $2.8 million during the year ended December 31, 2017. See Note 7. *Asset Retirement Obligations* for more information.

Costs incurred in oil and natural gas activities were as follows:

In thousands	Year Ended December 31, 2018	Year Ended December 31, 2017
Property acquisition costs:		
Unproved properties	$ 4,674	$ 116,775
Proved properties	40,865	7,745
Exploration costs	228	1,200
Development costs	167,914	91,882
Total costs incurred	$ 213,681	$ 217,602

Results of Operations

The following presents the results of operations from oil and natural gas producing activities:

In thousands	Year Ended December 31, 2018	2017
Oil sales	$ 167,743	$ 80,505
Natural gas liquid sales	18,471	7,086
Natural gas sales	14,955	6,477
Lease operating and gas gathering	(26,008)	(17,385)
Production and ad valorem taxes	(11,029)	(5,523)
Depreciation, depletion and amortization	(83,582)	(56,957)
Property impairment	(12,169)	(33,413)
Net operating income (loss)	68,381	(19,210)
Income tax (expense) benefit	(14,360)	6,724
Results of operations from oil and natural gas producing activities	$ 54,021	$ (12,486)

Crude Oil and Natural Gas Reserves

The reserve information presented below is based upon estimates of net proved oil and natural gas reserves that were prepared by W.D. Von Gonten & Co., independent petroleum engineers, located in Houston. These oil and natural gas reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

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 in future years from known reservoirs under existing economic conditions, operating methods and governmental regulations (i.e. historical average prices and costs as of the date the estimate is made). The project to extract the hydrocarbons must have commenced or the interest owner must be reasonably certain that it will commence within a reasonable period of time.

Reservoir engineering, which is the process of estimating quantities of crude oil and natural gas reserves, is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent upon many variables, and changes occur as knowledge of these variables evolves. Therefore, these estimates are inherently imprecise, and are subject to considerable upward or downward adjustments. Actual production, revenues and expenditures with respect to reserves will likely vary from estimates, and such variances could be material. In addition, reserve estimates for properties which have not yet been drilled, or properties with a limited production history may be less reliable than estimates for properties with longer production histories. All of the Company's reserves are located in the United States.

Estimated Quantities of Proved Reserves

	Oil (MBbl)	NGLs (MBbl)	Gas (MMcf)	MBOE (6:1)[(1)]
Net proved reserves				
Reserves at December 31, 2016	24,288	7,466	52,714	40,540
New discoveries and extensions	3,203	468	2,093	4,021
Purchase of reserves in place	23,614	3,422	16,867	29,847
Revisions of prior year estimates	1,176	(96)	2,570	1,507
Production	(1,580)	(385)	(2,370)	(2,360)
Reserves at December 31, 2017	50,701	10,875	71,874	73,555
New discoveries and extensions	4,781	1,773	10,228	8,259
Purchase of reserves in place	2,119	3,895	31,566	11,276
Revisions of prior year estimates	(1,618)	4,143	11,120	4,378
Production	(2,484)	(817)	(4,623)	(4,072)
Reserves at December 31, 2018	53,499	19,869	120,165	93,396
Proved Developed Reserves:				
December 31, 2016	6,268	2,274	14,734	10,998
December 31, 2017	12,657	2,846	17,034	18,342
December 31, 2018	15,459	5,721	34,388	26,912
Proved Undeveloped Reserves:				
December 31, 2016	18,021	5,191	37,980	29,542
December 31, 2017	38,044	8,029	54,840	55,213
December 31, 2018	38,040	14,147	85,777	66,484

(1) MBOE (One thousand barrels of oil equivalent) is calculated by converting six MMcf of natural gas to one MBbl of oil. A MBbl (barrel) of oil is one thousand stock tank barrels, or 42 thousand U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

2018 Changes in Reserves

The Company's proved oil and natural gas reserves increased to 93,396 MBOE at December 31, 2018 from 73,555 MBOE at December 31, 2017. The Company's proved oil and natural gas reserves increased by 23,913 MBOE and the Company produced 4,072 MBOE during the year ended December 31, 2018, resulting in a net increase of 19,841 MBOE. An increase of 11,276 MBOE was the result of the purchase of reserves in place, which primarily came from reserves acquired through the Sooner Acquisition in November 2018.

An increase of 8,259 MBOE in 2018 was the result of new discoveries and extensions, which was primarily attributable to drilling operations in the Western and Central Eagle Ford. The Company's proved oil and natural gas reserves also increased by 4,378 MBOE during 2018 due to revisions of prior estimates, which were primarily attributable to higher weighted-average oil and natural gas prices used to estimate proved reserves in 2018, as compared to 2017.

The Company's proved developed oil and natural gas reserves increased to 26,912 MBOE at December 31, 2018 from 18,342 MBOE at December 31, 2017, primarily due to drilling operations in the Western and Central Eagle Ford, as well as proved developed reserves acquired as part of the Sooner Acquisition.

At December 31, 2018, the Company's proved reserves were made up of approximately 79% oil and 21% natural gas, and were approximately 29% proved developed and approximately 71% proved undeveloped.

2017 Changes in Reserves

The Company's proved oil and natural gas reserves increased to 73,555 MBOE at December 31, 2017 from 40,540 MBOE at December 31, 2016. The Company's proved oil and natural gas reserves increased by 35,375 MBOE and the Company produced 2,360 MBOE during the year ended December 31, 2017, resulting in a net increase of 33,015 MBOE. An increase of 29,847 MBOE was the result of the purchase of reserves in place, which primarily came from reserves acquired through the Battlecat and Marquis Acquisitions in June 2017.

An increase of 4,021 MBOE in 2017 was the result of new discoveries and extensions, which was primarily attributable to drilling operations in the Western and Central Eagle Ford. The Company's proved oil and natural gas reserves also increased by 1,507 MBOE during 2017 due to revisions of prior estimates, which were attributable to better-than-projected well performance from certain wells and higher weighted-average oil and natural gas prices used to estimate proved reserves in 2017, as compared to 2016.

The Company's proved developed oil and natural gas reserves increased to 18,342 MBOE at December 31, 2017 from 10,998 MBOE at December 31, 2016, primarily due to proved developed reserves purchased as part of the Battlecat and Marquis Acquisitions in June 2017, as well as drilling operations in the Western and Central Eagle Ford.

At December 31, 2017, the Company's proved reserves were made up of approximately 84% oil and 16% natural gas, and were approximately 25% proved developed and approximately 75% proved undeveloped.

Standardized Measure of Discounted Future Net Cash Flows

Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes that such information is essential for a proper understanding and assessment of the data presented.

For the years ended December 31, 2018 and 2017, calculations were made using average prices of $65.66 and $51.34 per barrel of crude oil, respectively, and $3.10 and $2.98 per MCF of natural gas, respectively. NGL pricing used was approximately 30% of crude oil prices. Prices and costs are held constant for the life of the wells; however, prices are adjusted by well in accordance with sales contracts, energy content quality, transportation, compression and gathering fees, and regional price differentials.

These assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC, and do not necessarily reflect the Company's expectations of the actual net cash flow to be derived from those reserves, nor the present worth of the properties. Further, actual future net cash flows will be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, and changes in governmental regulations and tax rates. Sales prices of both crude oil and natural gas have fluctuated significantly in recent years.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expense includes the effect of statutory tax rates and the impact of tax deductions, tax credits and allowances, and application of NOL's to proved reserves. As a result of recent Tax Reform Legislation, statutory rates of 21% and 35% were used for years ended December 31, 2018 and 2017, respectively.

A 10% annual discount rate is used to reflect the timing of the future net cash flows relating to proved reserves.

The standardized measure of discounted future net cash flows was as follows:

	As of December 31,	
In thousands	2018	2017
Future cash flows	$ 4,501,757	$ 3,067,159
Future costs		
Production	(1,222,947)	(950,114)
Development	(901,750)	(854,175)
Future inflows before income tax	2,377,060	1,262,870
Future income taxes	(337,748)	(149,767)
Future net cash flows	2,039,312	1,113,103
10% annual discount for estimated timing of cash flows	(1,059,179)	(633,514)
Standardized measure of discounted future net cash flows	$ 980,133	$ 479,589

Changes in the standardized measure of discounted future net cash flows relating to proved crude oil and nature gas reserves were as follows:

In thousands	Year Ended December 31, 2018	2017
Standardized measure at beginning of year	$ 479,589	$ 145,833
Sales of oil and natural gas produced, net of production costs	(165,304)	(74,005)
Net change in sales price, net of production costs	283,658	135,555
Extensions and discoveries, net of future production and development costs	121,983	43,070
Changes in estimated future development costs	(4,948)	(46,050)
Revisions of quantity estimates	60,400	11,939
Changes of production rates (timing) and other	172,826	63,015
Accretion of discount	53,826	16,648
Purchase of minerals in place	78,752	221,610
Net change in income taxes	(100,649)	(38,026)
Net increase	500,544	333,756
Standardized measure at end of year	$ 980,133	$ 479,589

Exhibit 21.1

The following is a list of subsidiaries of the Company as of December 31, 2018:

Subsidiary	Jurisdiction of Incorporation
Lonestar Resources America, Inc.	Delaware
Lonestar Resources, Inc.	Delaware
Lonestar Resources Intermediate, Inc.	Delaware
LNR America, Inc.	Delaware
Eagleford Gas, LLC	Texas
Poplar Energy, LLC	Texas
Eagleford Gas 2, LLC	Texas
Eagleford Gas 3, LLC	Texas
Eagleford Gas 4, LLC	Texas
Eagleford Gas 5, LLC	Texas
Eagleford Gas 6, LLC	Texas
Eagleford Gas 7, LLC	Texas
Eagleford Gas 8, LLC	Texas
Eagleford Gas 10, LLC	Texas
Eagleford Gas 11, LLC	Texas
Boland Building, LLC	Texas
Lonestar Operating, LLC	Texas
Lonestar BR Disposal, LLC	Texas
La Salle Eagle Ford Gathering Line, LLC	Texas
Amadeus Petroleum, Inc.	Texas
T-N-T Engineering, Inc.	Texas
Albany Services, LLC	Texas

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

Lonestar Resources US Inc.
Fort Worth, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-219759) and Form S-3 (No. 333-221392) of Lonestar Resources US Inc. of our report dated March 13, 2019, relating to the consolidated financial statements, which appears in this Form 10-K.

/s/BDO USA, LLP
Dallas, Texas
March 13, 2019

Exhibit 23.2

Consent of Independent Petroleum Engineers

We hereby consent to the references to our firm in the Annual Report on Form 10-K for Lonestar Resources US Inc. (the "Form 10-K") and to the inclusion of our report, dated February 19, 2019, with respect to the estimates of reserves and future net revenues as of December 31, 2018, and to the inclusion of our report, dated February 20, 2018, with respect to the estimates of reserves and future net revenues as of December 31, 2017, in the Form 10-K and/or as an exhibit to the Form 10-K.

W.D. VON GONTEN & CO.

/s/ William D. Von Gonten, Jr.
William D. Von Gonten, Jr.
President

Houston, Texas
March 13, 2019

Exhibit 31.1

CERTIFICATIONS

I, Frank D. Bracken, III, certify that:

1. I have reviewed this Annual Report on Form 10-K of Lonestar Resources US Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 13, 2019

/s/ Frank D. Bracken, III

Frank D. Bracken, III

Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, Jason N. Werth, certify that:

1. I have reviewed this Annual Report on Form 10-K of Lonestar Resources US Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 13, 2019

/s/ Jason N. Werth

Jason N. Werth

Chief Accounting Officer
(Principal Financial Officer)

Exhibit 32.1

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 Lonestar Resources US Inc. (the “Company”) on Form 10-K for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Form 10-K”), I, Frank D. Bracken III, Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and result of operations of the Company.

March 13, 2019	/s/ Frank D. Bracken, III
	Frank D. Bracken, III
	Chief Executive Officer

Exhibit 32.2

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 Lonestar Resources US Inc. (the "Company") on Form 10-K for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, Jason N. Werth, Chief Accounting Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: March 13, 2019

/s/ Jason N. Werth

Jason N. Werth
Chief Accounting Officer

February 19, 2019

Lonestar Resources US Inc. 111
Boland Street, Suite 300 Fort
Worth, TX 76107

Re: Lonestar Resources US Inc.
Estimate of Reserves and Revenues
2018 SEC Year-End Pricing
"As of" December 31, 2018

Ladies and Gentlemen:

At your request, W.D. Von Gonten & Co. (Von Gonten) has prepared estimates of future reserves and projected net revenues for certain property interests owned by Lonestar Resources US Inc. (Lonestar). The reserves and income data were estimated in accordance with the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC), including the reserves definitions of Rule 4-10(a)(1)(33) of Regulation S-X. Our third party study, completed on January 23, 2019, and presented herein, was prepared for public disclosure by Lonestar in filings made with the SEC in accordance with Item 1202(a)(8) of Regulation S-K.

The properties evaluated by Von Gonten account for 100% of Lonestar's total net Proved reserves "as of" December 31, 2018.

The results of the study are summarized as follows:

	Net to Lonestar Resources US Inc.			
	Proved Developed		Proved Undeveloped	Total Proved
SEC Pricing	Producing	Non-Producing		
Reserve Estimates				
Oil/Cond., Mbbl	15,386.2	72.9	38,040.3	53,499.4
Gas, MMcf	34,388.2	0	85,776.5	120,164.7
NGL, Mbbl	5,721.5	0	14,147.3	19,868.8
Oil/Cond. Equivalent, MBOE	26,839.1	72.9	66,483.7	93,395.7
Proved Revenues				
Oil, $ (80.2) %	1,038,348,288	4,976,816	2,565,962,752	3,609,287,936
Gas, $ (8.5) %	109,247,904	0	272,577,024	381,824,960
NGL, $ (11.3) %	146,844,736	0	363,798,528	510,643,232
Total, $	1,294,441,216	4,976,816	3,202,338,304	4,501,755,904
Expenditures				
Advalorem Taxes, $	20,337,272	71,218	49,924,984	70,333,480
Severance Taxes, $	65,731,504	228,934	159,461,552	225,421,952
Direct Operating Expense, $	440,827,712	1,175,265	324,817,408	766,820,480
Variable Operating Expense, $	24,724,364	1,186,040	65,134,468	91,044,872
Transportation Expense, $	20,933,572	0	48,393,224	69,326,784
Total, $	572,554,432	2,661,456	647,731,584	1,222,947,584
Investments				
Total, $	4,865,716	796,145	896,087,808	901,749,568
Estimated Future Net Revenues(FNR)				
Undiscounted FNR, $	717,020,800	1,519,214	1,658,519,424	2,377,059,328
FNR Disc. @ 10%, $	471,927,648	800,353	666,725,888	1,139,453,824
Allocation Percentage by Classification FNR Disc. @ 10%	41.4%	0.1%	58.5%	100.0%

*Due to computer rounding, numbers in the above table may not sum exactly.

Report Qualifications

Purpose of Report -The purpose of this report is to be used in connection with Lonestar's public disclosures with the SEC, in accordance with SEC rules and regulations.

Scope of Work - W.D. Von Gonten & Co. was engaged by Lonestar to estimate the remaining reserves and future production forecasts associated with the producing and undeveloped properties included in this report. Once reserves were estimated, future net revenues were determined utilizing a provided 2018 SEC Year-End pricing scenario.

Reporting Requirements - Securities and Exchange Commission (SEC) Regulation S-K, Item 102 and Regulation S-X, Rule 4-10, and Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, Extractive Activities - Oil and Gas requires oil and gas reserves information to be reported by publicly held companies as supplemental financial information. These regulations and standards provide for estimates of Proved reserves and revenues discounted at 10% and based on constant prices and costs.

The Securities and Exchange Commission Regulation S-X definitions of proved reserves are as follows:

Proved Reserves; Securities and Exchange Commission Regulation S-X §210.4-10(a)(22)

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.

Developed Reserves-Securities and Exchange Commission Regulation S-X §210.4-10(a)(6)

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.

Undeveloped Reserves-Securities and Exchange Commission Regulation S-X §210.4-10(a)(31)

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. (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, or by other evidence using reliable technology establishing reasonable certainty.

Projections - The attached reserves and revenue projections are on a calendar year basis with the first time period being January 1, 2019 through December 31, 2019.

Property Discussion

The Lonestar properties include producing and undeveloped locations located in Brazos, DeWitt, Dimmit, Fayette, Frio, Gonzales, Karnes, LaSalle, Lavaca, Robertson, and Wilson Counties, Texas. Lonestar currently owns interests in 284 Proved Developed Producing (PDP) wells, of which, 237 are horizontal Eagle Ford shale wells. Lonestar currently operates 203 of the total producing wells. As of December 31, 2018, the current gross production rates from all of the producing wells are approximately 12,400 barrels of oil and 34,900 Mcf of gas per day.

Currently, there are 177 Proved Undeveloped (PUD) locations to be completed in the Eagle Ford shale, of which, 169 will be operated by Lonestar. The first well is scheduled to start producing in March 2019.

Reserves Estimates

Producing and Non-Producing Properties - Reserve estimates for the PDP and Proved Non- Producing (PNP) properties were based on volumetric calculations, log analysis, decline curve analysis, and/or analogy to nearby production. Where applicable, these estimates were further supported by rate transit analysis and/or numerical reservoir simulation as part of a shale field study conducted by us independent of this report.

Undeveloped Properties - The undeveloped reserves were necessarily estimated using volumetric calculations, log analysis, core analysis, geophysical interpretation and reservoir simulation. In addition, W.D. Von Gonten & Co. has performed a field study of the Eagle Ford shale play independent of this report. Our conclusions from that field study have fortified our confidence in the producing and undeveloped reserves included herein.

Based on SEC reserves reporting requirements, only those undeveloped volumes scheduled to be drilled within five years of their initial recognition have been included within the Proved Undeveloped category of reserves.

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.

We consider the assumptions, data, methods, and procedures used in this report appropriate hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves and future net revenues.

Product Prices

The estimated revenues shown herein were based on SEC Year-End pricing guidelines effective December 31, 2018. 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. The provided scenario utilized for this report is a price of $65.56 per barrel of oil and $3.10 per MMBtu of gas. These prices were held constant throughout the life of the properties, as per SEC guidelines.

Pricing differentials were applied to all properties on an individual property basis in order to reflect prices actually received at the wellhead. Pricing differentials are typically utilized to account for transportation charges, geographical differentials, quality adjustments, any marketing bonuses or deductions, and any other factors that may affect the price actually received at the wellhead. Lonestar provided historical pricing data for the twelve month time period ended October 2018. W.D. Von Gonten & Co. applied the historical averages extracted from the pricing data for this report. The natural gas liquids (NGL) price differential utilized in this evaluation was based on a comparison of the historical price received versus the average NYMEX oil price. The average realized prices, after applying the pricing adjustments, for the reserves included in this report are as set forth in the table below:

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$65.56/Bbl	$67.50/Bbl
	NGLs	WTI Cushing	$65.56/Bbl*	$25.68/Bbl
	Gas	Henry Hub	$3.10/MMBtu	$3.18/MMBtu

A gas volume shrinkage factor has been applied to each property. This shrinkage accounts for any line loss, generation of NGLs, and/or fuel usage before the actual sales point.

Operating Expenses and Capital Cost

Historical monthly operating expense data ranging from November 2017 through October 2018 for the properties were provided by Lonestar. W.D. Von Gonten & Co. applied a combination of fixed and variable monthly expenses to each individual property.

Capital costs necessary to perform well completion operations and to develop undeveloped locations were supplied by Lonestar. Where available, these costs were verified from actual recent work in the area of interest and/or provided Authorities for Expenditures (AFEs).

All operating expenses and capital costs were held flat for the life of the properties in accordance with SEC guidelines.

Other Considerations

Abandonment Costs - Cost estimates regarding future plugging and abandonment procedures associated with these properties were supplied by Lonestar 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 this assumption.

Additional Costs - Costs were not deducted for general and administrative expenses, depletion, depreciation and/or amortization (a non-cash item), or federal income tax.

Data Sources - Data furnished by Lonestar included basic well information, lease acreage maps, ownership interests, completion and drilling reports, pricing contracts, and daily production data. Public data sources such as IHS Energy and the U.S. Geological Survey (USGS) were used to gather any additional necessary data.

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. The estimation of fair market value for oil and gas properties requires additional analysis other than evaluating undiscounted and discounted future net revenues.***

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 December 31, 2018 estimated oil and gas volumes. The reserves in this report can be produced under current regulatory guidelines. Actual future commodity prices may differ substantially from the utilized pricing scenario which may or may not extend or limit the estimated 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 reserves and revenue estimates produced in this report.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The Proved reserves included herein were determined in conformance with all applicable SEC rules and regulations, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the Proved reserves presented in this report comply with the definitions, guidelines, and disclosure requirements as required by the SEC Regulations.

Thank you for the opportunity to assist Lonestar Resources US Inc. with this project.

Respectfully submitted,

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/s/ Taylor D. Matthes
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