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, 2020
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 001-36057

Ring Energy, Inc.

(Exact name of registrant as specified in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	**90-0406406** (I.R.S. Employer Identification Number)
1725 Hughes Landing Blvd. Suite 900 **The Woodlands, TX** (Address of principal executive offices)	**77380** (Zip Code)

(281) 397-3699
(Registrant's telephone number, including area code)

Securities registered under Section 12(b) of the Exchange Act:

Title of Each Class	Trading Symbol	Name of Exchange
Common Stock, par value $0.001	REI	NYSE American

Securities registered under Section 12(g) of the Exchange 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 Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No

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

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

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

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

As of June 30, 2020, the aggregate market value of the common voting stock held by non-affiliates of the issuer, based upon the closing stock price on the NYSE American of $1.16 per share, was $74,553,881.

As of March 16, 2021, the issuer had outstanding 99,181,587 shares of common stock ($0.001 par value).

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Report, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement relating to the Annual Meeting of Stockholders to be held in 2021, which definitive proxy statement shall be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Report relates.

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Forward Looking Statements

This Annual Report on Form 10-K (herein, "Annual Report") contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact included in this Annual Report regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "would," "should," "believe," "anticipate," "intend," "estimate," "expect," "project" or other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. All forward-looking statements speak only as of the date of this Annual Report. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We are making investors aware that such forward-looking statements, because they relate to future events, are by their very nature subject to many important factors that could cause actual results to differ materially from those contemplated. Such factors include: declines or volatility in the prices we receive for our oil and natural gas; our ability to raise additional capital to fund future capital expenditures; our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop and produce our oil and natural gas properties; general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business; risks associated with drilling, including completion risks, cost overruns and the drilling of non-economic wells or dry holes; uncertainties associated with estimates of proved oil and natural gas reserves; the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs; risks and liabilities associated with acquired companies and properties; risks related to integration of acquired companies and properties; potential defects in title to our properties; cost and availability of drilling rigs, equipment, supplies, personnel and oilfield services; geological concentration of our reserves; environmental or other governmental regulations, including legislation of hydraulic fracture stimulation; our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices; exploration and development risks; management's ability to execute our plans to meet our goals; our ability to retain key members of our management team on commercially reasonable terms; the occurrence of cybersecurity incidents, attacks or other breaches to our information technology systems or on systems and infrastructure used by the oil and gas industry; weather conditions; actions or inactions of third-party operators of our properties; costs and liabilities associated with environmental, health and safety laws; our ability to find and retain highly skilled personnel; operating hazards attendant to the oil and natural gas business; competition in the oil and natural gas industry; evolving geopolitical and military hostilities in the Middle East; the ongoing COVID-19 pandemic, including any reactive or proactive measures taken by businesses, governments and by other organizations related thereto, and the direct and indirect effects of COVID-19 on the market for and price of oil; and the other factors discussed in Part I, Item 1A-- "Risk Factors" in this Annual Report, as well as in our consolidated financial statements, related notes, and the other financial information appearing elsewhere in this Annual Report and our other reports filed from time to time with the Securities and Exchange Commission (the "SEC").

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date that such statements are made. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

Unless the context otherwise requires, references in this Annual Report to "Ring," "Ring Energy," "the Company," "we," "us," "our" or "ours" refer to Ring Energy, Inc.

PART I

Item 1: Business

General

Ring Energy, Inc., a Nevada corporation ("Ring," "Ring Energy," the "Company," "we," "us," "our," or similar terms), is a growth oriented independent exploration and production company based in The Woodlands, Texas and is engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in Texas and New Mexico. Our primary drilling operations target the oil and liquids rich producing formations in the Northwest Shelf, the Central Basin Platform, and the Delaware Basin all of which are part of the Permian Basin in Texas and New Mexico.

As of December 31, 2020, our leasehold acreage positions totaled 104,455 gross (76,745 net) acres and we held interests in 610 gross (441 net) producing wells. Proved reserves as of December 31, 2020 were approximately 76.5 million BOE (barrel of oil equivalent), of which we are the operator of approximately 97.7%. All of our properties are located in the Permian Basin in Texas and New Mexico. The Company's proved reserves are oil-weighted with approximately 87% consisting of oil and 13% consisting of natural gas. Of those reserves, approximately 57.5% are classified as proved developed or "PD" and 42.5% are classified as proved undeveloped, or "PUD." For the calculation of BOE, oil is weighted on a 6 to 1 ratio against natural gas.

Our Mission

Ring's mission is to deliver competitive and sustainable returns to its shareholders by developing, acquiring, exploring for, and commercializing oil and natural-gas resources vital to the world's health and welfare.

Our Business Strategy

Successfully achieving Ring's mission requires a firm commitment to operating safely in a socially responsible and environmentally friendly manner. Key principles supporting Ring's new strategic vision are to:

- ensure health, safety, and environmental excellence and a strong commitment to Ring's employees and the communities in which we work and operate;
- continue our focus on generating free cash flow to improve and build a sustainable financial foundation;
- pursue rigorous capital discipline focused on Ring's highest returning opportunities;
- improve margins and drive value by targeting additional operating cost reductions and capital efficiencies; and
- strengthen the balance sheet by steadily paying down debt, divesting of non-core assets and becoming a peer leader in Debt/EBITDA metrics.

Our new strategic vision is guided by these key principles and implemented by pursuing the following five strategic objectives.

Attract and retain the best people - Achieving our mission will only be possible through our employees. It is critical to have compensation, development, and human resource programs that attract, retain and motivate the types of people we need to succeed.

Pursue operational excellence with a sense of urgency - We plan to deliver low cost, consistent, timely and efficient execution of our drilling campaigns, work programs and operations. We will execute our operations in a safe and environmentally responsible manner, apply advanced technologies, and continuously seek ways to reduce our operating cash costs on a per barrel basis. This objective is a foundational aspect of our culture and future success.

Invest in high-margin, high rate-of-return projects - Another key to achieving our mission will be to prioritize our work programs and allocate capital to the highest return opportunities in our inventory. This objective is key to profitably growing our production and reserve levels and generating the excess cash from operations to pay down debt.

Focus on generating free cash flow and strengthen our balance sheet - Ring intends to reduce its long-term debt through the use of excess cash from operations and potentially through the sale of non-core assets. Ring incurred long-term indebtedness in connection with the acquisition of core assets from Wishbone Energy Partners, LLC and its related entities in 2019. Continuing to generate free cash flow through a disciplined capital allocation program and reducing our operating and corporate costs are key components of this objective. Our capital program will be funded by operational cash flow, limited to maintain or minimally grow our production and reserve levels, and have returns sufficient to provide excess cash from operations to pay down debt. Remaining focused and disciplined in this regard will lead to meaningful returns for our shareholders once our financial position improves and additional financial flexibility to manage swings in the business cycle. Our commodity hedges are designed to ensure the necessary cash flow to adhere to these plans.

Pursue strategic acquisitions that maintain or reduce our break-even costs - We will actively pursue accretive acquisitions, mergers and dispositions that improve our margins, returns, and break-even costs of our investment portfolio. Financial strategies associated with these efforts will focus on delivering competitive debt-adjusted per share returns. This objective is key to delivering competitive returns to our shareholders on a sustainable basis.

2019 Acquisition

In 2019, a significant portion of the increase in acreage and reserves was the result of our acquisition of properties from Wishbone Energy Partners, LLC, Wishbone Texas Operating Company LLC and WB WaterWorks LLC on the Northwest Shelf in Gaines, Yoakum, Runnels and Coke Counties, Texas and Lea County, New Mexico that was completed in April 2019. This acquisition contributed all of the acreage we have on the Northwest Shelf. It also contributed approximately 45.3 million BOE of our 81.1 million BOE of proved reserves as of December 31, 2019.

Appointment and Departure of Certain Officers and Directors

On September 30, 2020, the Company announced the appointment of Mr. Paul D. McKinney as Chief Executive Officer ("CEO") and Chairman of the Board of Directors (the "Board"), effective October 1, 2020. In connection with the appointment of Mr. McKinney, Lloyd T. Rochford, Chairman of the Board, and Kelly Hoffman, CEO, resigned from their respective positions, effective as of October 1, 2020. Mr. Rochford and Mr. Hoffman also resigned from the Board on October 1, 2020. Mr. Rochford remains with the Company in a consulting capacity as an advisor to the CEO and Chairman of the Board.

On October 22, 2020, the Company appointed Mr. Thomas L. Mitchell to the Company's Board and determined that Mr. Mitchell is an "independent director" as such term is defined under the NYSE American Company Guide.

On October 29, 2020, the Company appointed Mr. John A. Crum and Mr. Richard E. Harris to the Company's Board and determined that Mr. Crum and Mr. Harris are "independent directors" as such term is defined under the NYSE American Company Guide. In connection with the appointment of Mr. Crum and Mr. Harris, Mr. Stanley McCabe and Mr. David Fowler resigned from the Board on and effective October 29, 2020.

On November 30, 2020, the Company announced the promotion of Mr. Stephen D. Brooks to Executive Vice President of Land, Legal, Human Resources and Marketing, assuming roles previously held by Mr. Matt Garner who served as General counsel and Vice President of land for the company.

On December 16, 2020, Company issued a press release announcing several executive management changes, effective December 31, 2020. The Company announced the promotion of Mr. Alexander Dyes to Executive Vice President of Engineering and Corporate Strategy, the promotion of Mr. Marinos Baghdati to Executive Vice President of Operations, and the promotion of Ms. Hollie Lamb to Vice President of Compliance and General Manager of the Company's Midland, Texas office. In connection with these changes, Mr. David A. Fowler resigned from his position as President but remains with the Company in a consulting capacity and manages Investor Relations and Mr. Danny Wilson resigned from his position as Executive Vice President and Chief Operating Officer.

Primary Business Operations

The Company seeks to exploit its acreage position through the drilling of highly economic vertical and horizontal wells using the most recent drilling and completion techniques. Our focus is drilling and developing our oil and gas properties through use of cash flow generated by our operations and reducing our long-term debt through the sale of non-core assets or through our excess cash flow while still working towards maintaining or providing annual production growth. We continue to evaluate potential transactions to acquire attractive acreage positions within our core areas of interest.

Ring's original plan for 2020 included drilling 18 horizontal wells on the Northwest Shelf and performing workovers and extensive infrastructure projects on its Northwest Shelf, Central Basin Platform and Delaware Basin assets. Due to the drop in the price of oil, Ring re-evaluated its capital expenditure budget for 2020 and made changes that the Company believed were in the best interest of its stockholders, including ceasing any further drilling until oil prices stabilized. Of the 18 new wells originally planned, the Company drilled four new horizontal San Andres wells on its Northwest Shelf asset in the first quarter of 2020 and two more new horizontal San Andres wells in the same asset area in December 2020. All four new wells drilled in the first quarter were completed, tested and had Initial Potentials ("IP") filed. In addition to the four new wells drilled in the first quarter which had IPs filed, the Company completed testing and filed IPs on two additional horizontal wells drilled in 2019. The Company performed nine conversions from electrical submersible pumps to rod pumps in the first quarter 2020, four conversions in the second quarter 2020, eight conversions in the third quarter 2020 and eight conversions in the fourth quarter 2020. Starting the last week of April, the Company shut-in or curtailed essentially all production, other than that associated with Ring's Delaware Basin property. The curtailments continued until early June, when, with commodity prices improving and price differentials decreasing, the Company began to bring wells back on-line, returning to near April levels by the end of the second quarter. In the third quarter 2020, we restored production to 9,549 net barrels of oil equivalent per day ("BOEPD"). In the fourth quarter 2020, the Company performed capital workovers and re-activations that stabilized production at 9,307 BOEPD. In view of the uncertainty of the extent of the contraction in oil demand and the volatility of oil futures contracts due to the COVID-19 pandemic, combined with the generally weaker commodity price environment, the Company turned its strategic focus in 2020 to reducing costs, generating free cash flow, and paying down debt.

Ring believes that there is significant value to be created by drilling the identified undeveloped opportunities on its Texas and New Mexico properties and intends to focus its drilling efforts in 2021 primarily in the Northwest Shelf.

- *Northwest Shelf – Yoakum, Runnels and Coke Counties, Texas and Lea County, New Mexico* – As of December 31, 2020, Ring owned interests in a total of 11,723 gross (8,085 net) developed acres and 35,249 gross (24,830 net) undeveloped acres. In these counties, the Company has 72 identified proved horizontal drilling locations and 11 proved vertical drilling locations based on the reserve reports as of December 31, 2020 and an additional 70 potential vertical drilling locations based on 20-acre downspacing and 135 potential horizontal drilling locations based on 4-8 wells per section or 80-160 acres per well.

- *Central Basin Platform – Andrews and Gaines Counties, Texas* – As of December 31, 2020, Ring owned interests in a total of 23,668 gross (18,712 net) developed acres and 15,046 gross (6,650 net) undeveloped acres. In these counties, the Company has 2 identified proved vertical drilling locations and 32 identified proved horizontal locations based on the reserve reports as of December 31, 2020, and an additional 105 potential vertical drilling locations based on 10-acre downspacing and 179 potential horizontal drilling locations based on 6 wells per section or 106 acres per well.

- *Delaware Basin – Culberson and Reeves Counties, Texas* – As of December 31, 2020, Ring owned interests in a total of 18,521 gross (18,256 net) developed acres and 248 gross (212 net) undeveloped acres. In these counties, the Company has 26 identified proved vertical drilling locations and 4 identified proved horizontal locations based on the reserve reports as of December 31, 2020 and an additional 17 potential vertical drilling locations based on 10-acre spacing and 59 potential horizontal drilling locations based on 4 wells per section or 160 acres per well.

Ring intends to grow its reserves and production through development, drilling, exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through acquisitions that meet the Company's strategic and financial objectives, targeting oil-weighted reserves.

Ring Energy's Strengths

- high quality asset base in one of North America's leading oil and gas producing regions characterized by low declines and attractive margins;
- de-risked Permian Basin acreage position with multi-year drilling inventory of horizontal and vertical development potential;
- concentrated acreage position with high degree of operational control;
- experienced and proven management team focused on the Permian Basin;

- history of attracting technical personnel with experience in our core area of operations;
- commitment to cost efficient operations, health, safety, protecting the environment, our employees, and the communities in which we work and operate.

Competitive Business Conditions

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Some of our competitors possess and employ financial resources substantially greater than ours and some of our competitors employ more technical personnel. These factors can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects, and to evaluate, bid for, and purchase a greater number of properties and prospects than what our financial or technical resources permit. Our ability to acquire additional properties and to find and develop reserves in the future will depend on our ability to identify, evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Marketing and Pricing

The actual price range of crude oil is largely established by major crude oil purchasers and commodities trading. Pricing for natural gas is based on regional supply and demand conditions. To this extent, we believe we receive oil and natural gas prices comparable to other producers. We believe there is little risk in our ability to sell our production at prevailing prices. We view potential declines in oil and gas prices to a level which could render our current production uneconomical as our primary pricing risk.

We are presently committed to use the services of the existing gathering systems of the companies that purchase our natural gas production. This commitment is tied to existing natural gas purchase contracts associated with our production, which potentially gives such gathering companies certain short-term relative monopolistic powers to set gathering and transportation costs. Obtaining the services of an alternative gathering company would require substantial additional costs (since an alternative gathering company would be required to lay new pipeline and/or obtain new rights of way to any lease from which we are selling production).

We are not subject to third-party gathering systems with respect to our oil production. Some of our oil production is sold through a third-party pipeline which has no regional competition and all other oil production is transported by the oil purchaser by trucks with competitive trucking costs in the area.

Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities.

For the fiscal year ended December 31, 2020, sales to three customers, Phillips 66 (“Phillips”), Occidental Energy Marketing (“Oxy”) and NGL Crude Partners (“NGL Crude”) represented 68%, 10% and 8%, respectively, of our oil and natural gas revenues. As of December 31, 2020, Phillips represented 80% of our accounts receivable, Oxy represented 0% of our accounts receivable and NGL Crude represented 5% of our accounts receivable. We believe that the loss of any of these customers would not materially impact our business because we could readily find other purchasers for our oil and natural gas.

Delivery Commitments

As of December 31, 2020, we were not committed to providing a fixed quantity of oil or gas under any existing contracts.

Governmental Regulations

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, can affect our profitability.

Regulation of Drilling and Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The trend in oil and natural gas regulation has been to increase regulatory restrictions and limitations on such activities. Any changes in, or more stringent enforcement of, these laws and regulations may result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management or completion activities or waste handling, storage, transport, remediation, or disposal emission or discharge requirements which could have a material adverse effect on the Company. For example, on January 20, 2021, the Biden Administration placed a 60-day moratorium on new oil and gas leasing and drilling permits on federal land, and on January 27, 2021, the Department of Interior acting pursuant to a Presidential Executive Order suspended the federal oil and gas leasing program indefinitely. The Biden Administration has also announced that it intends to review the Trump Administration's 2017 repeal of the 2015 rule regulating hydraulic fracturing activities in federal land under the Presidential Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis. While we do not have a significant federal lands acreage position at 240 net acres, these actions could have a material adverse effect on the Company and our industry.

Currently, all of our properties and operations are in Texas and New Mexico, which have regulations governing conservation matters, such as the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, both Texas and New Mexico impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices, however, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors. 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 shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing 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 competitors.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The 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. Although the 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.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

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

Environmental Compliance and Risks

Our oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. At the federal level, among the more significant laws that may affect our business and the oil and natural gas industry generally are: the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"); the Oil Pollution Act of 1990; the Resource Conservation and Recovery Act ("RCRA"); the Clean Air Act ("CAA"); Federal Water Pollution Control Act of 1972, or the Clean Water Act ("CWA"); and the Safe Drinking Water Act of 1974. These federal laws are administered by the United States Environmental Protection Agency ("EPA"). Generally, these laws (i) regulate air and water quality, impose limitations on the discharge of pollutants and establish standards for the handling of solid and hazardous wastes; (ii) subject our operations to certain permitting and registration requirements; (iii) require remedial measures to mitigate pollution from former or ongoing operations; and (iv) may result in the assessment of administrative, civil and criminal penalties for failure to comply with such laws. In addition, there is environmental regulation of oil and gas production by state and local governments in the jurisdictions where we operate. As described below, there are various regulations issued by the EPA and other governmental agencies pursuant to these federal statutes that govern our operations.

In Texas and New Mexico, specific oil and natural gas regulations apply to oil and gas operations, including the drilling, completion and operations of wells, and the disposal of waste oil and saltwater. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency.

At the federal level, among the more significant laws and regulations that may affect our business and the oil and natural gas industry are:

Hazardous Substances and Wastes

CERCLA, also known as the Superfund law, and analogous state laws impose liability on certain classes of persons, known as "potentially responsible parties," for the disposal or release of a regulated hazardous substance into the environment. These potentially responsible parties include (1) the current owners and operators of a facility, (2) the past owners and operators of a facility at the time the disposal or release of a hazardous substance occurred, (3) parties that arranged for the offsite disposal or treatment of a hazardous substance, and (4) transporters of hazardous substances to off-site disposal or treatment facilities. While petroleum and natural gas liquids are not designated as a "hazardous substance" under CERCLA, other chemicals used in or generated by our operations may be regulated as hazardous substances. Potentially responsible parties under CERCLA may be subject to strict, joint and several liability for the costs of investigating and cleaning up environmental contamination, for damages to natural resources and for the costs of certain health studies. In addition to statutory liability under CERCLA, common law claims for personal injury or property damage can also be brought by neighboring landowners and other third parties related to contaminated sites.

RCRA, and comparable state statutes and their implementing regulations, regulate the generation, transportation, treatment, storage, disposal and cleanup of solid and hazardous wastes. Under a delegation of authority from the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Certain wastes associated with the production of oil and natural gas, as well as certain types of petroleum-contaminated media and debris, are excluded from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated as solid waste (i.e., non-hazardous waste) under the less stringent provisions of Subtitle D of RCRA. It is possible, however, that certain wastes now classified as non-hazardous could be classified as hazardous wastes in the future and therefore be subject to more rigorous and costly disposal requirements. Legislation has been proposed from time to time in Congress to regulate certain oil and natural gas wastes as hazardous waste under RCRA. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our consolidated results of operations and financial position.

Under CERCLA, RCRA and analogous state laws, we could be required to remove or remediate environmental impacts on properties we currently own and lease or formerly owned or leased (including hazardous substances or wastes disposed of or released by prior owners or operators), to clean up contaminated off-site disposal facilities where our wastes have come to be located or to implement remedial measures to prevent or mitigate future contamination. Compliance with these laws may constitute a significant cost and effort for us. No specific accounting for environmental compliance has been maintained or projected by us at this time. We are not presently aware of any environmental demands, claims, or adverse actions, litigation or administrative proceedings in which either we or our acquired properties are involved in or subject to, or arising out of any predecessor operations.

Air Emissions

Our operations are subject to the federal CAA and comparable state and local laws and regulations, which regulate emissions of air pollutants from various sources and mandate certain permitting, monitoring, recordkeeping and reporting requirements. The CAA and its implementing regulations may require that we obtain permits prior to the construction, modification or operation of certain projects or facilities expected to produce or increase air emissions above certain threshold levels and strictly comply with those permits, including emissions and operational limitations. These permits may require us to install emission control technologies to limit emissions, which can impose significant costs on our business. We note that in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small sites into a single source for air permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities to be aggregated for permitting purposes, resulting in treatment as a major source, and thereby triggering more stringent air permitting requirements. Violation of CAA requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. Furthermore, future capital expenditures may be required for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

The trend under CAA regulations has been to increase the stringency of air quality standards, which may require us to incur capital expenditures for air pollution control equipment or other costs. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standards for ozone to 70 parts per billion, which was a significant decrease from the prior standards. On December 31, 2020, EPA published in the *Federal Register* its decision to retain the 2015 ozone standards; however, the current administration has announced that it intends to review this rule under the January 20, 2021 *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*. Further reductions in the ozone National Ambient Air Quality Standards could affect our operations and result in the need to install new emissions controls, longer permitting timelines and significant increases in our capital or operating expenditures. Compliance with these and any future air pollution control and permitting requirements has the potential to delay the development of our oil and natural gas projects and increase our costs of development and production, which costs could be significant.

Oil Pollution Prevention

The Oil Pollution Act of 1990 amended the CWA to impose liability for releases of crude oil from vessels or facilities into navigable waters. If a release of crude oil into navigable waters occurs during shipment or from an oil terminal, we could be subject to liability under the Oil Pollution Act. In 1973, the EPA adopted oil pollution prevention regulations under the CWA. These oil pollution prevention regulations require the preparation of a Spill Prevention Control and Countermeasure (“SPCC”) plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming crude oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. SPCC requirements under the CWA require appropriate containment berms and similar structures to help prevent the discharge of pollutants into regulated waters in the event of a crude oil or other constituent tank spill, rupture or leak. The SPCC regulations require affected facilities to prepare a written, site-specific SPCC plan, which details how a facility’s operations comply with the requirements of the pollution prevention regulations. To be in compliance, the facility’s SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intra-facility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. Where applicable, we maintain and implement SPCC plans for our facilities.

Water Discharges

The CWA and analogous state laws and regulations impose restrictions and strict controls regarding the discharge of pollutants into navigable waters, defined as waters of the United States ("WOTUS"), as well as state waters. The CWA prohibits the placement of dredge or fill material in wetlands or other WOTUS unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps") or a delegated state agency pursuant to Section 404. 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. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Also, in June 2016, the EPA issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly owned treatment works. This restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The scope of EPA's and the Corps' regulatory authority under Section 404 of the CWA has been the subject of extensive litigation and frequently changing regulations. The EPA issued a final rule in September 2015 that attempted to clarify the federal jurisdictional reach over WOTUS under Section 404 of the CWA. The EPA and the Corps issued a final rule in January 2018 staying implementation of the 2015 WOTUS rule for two years. On October 22, 2019, EPA and the Corps published a final rule repealing the 2015 WOTUS rule. The EPA and the Corps replaced the 2015 WOTUS rule by promulgating the Navigable Waters Protection Rule on April 21, 2020, which provides a revised definition of WOTUS and became effective on June 22, 2020. These regulations have been challenged in federal court, however, and the scope of the CWA's jurisdiction may remain fluid until all litigation is concluded. Further regulatory changes are likely, as the current administration has announced that it intends to review the Navigable Waters Protection Rule under the January 20, 2021 *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*. The pending litigation and future regulations concerning the definition of WOTUS may result in an expansion of the scope of the CWA's jurisdiction, and we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in WOTUS in connection with our operations.

Underground Injection Control

The underground injection of crude oil and natural gas wastes is regulated by the Underground Injection Control ("UIC") Program, as authorized by the Safe Drinking Water Act, as well as by state programs. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluid from the injection zone into underground sources of drinking water, as well as to prevent communication between injected fluids and zones capable of producing hydrocarbons. The Safe Drinking Water Act establishes requirements for permitting, testing, monitoring, recordkeeping, and reporting of injection well activities, as well as a prohibition against the migration of fluid containing contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in the suspension of permits, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties for property damages and personal injuries.

Under the auspices of the federal UIC program as implemented by states with UIC primacy, regulators, particularly at the state level, are becoming increasingly sensitive to possible correlations between underground injection and seismic activity. Consequently, state regulators implementing both the federal UIC program and state corollaries are heavily scrutinizing the location of injection facilities relative to faulting and are limiting both the density and injection facilities as well as the rate of injection.

Hydraulic Fracturing

Hydraulic fracturing is a practice in the oil and natural gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations by injecting water, sand and chemicals under pressure. Oil and natural gas may be recovered from certain of our oil and natural gas properties through the use of hydraulic fracturing. Hydraulic fracturing is subject to regulation by state regulatory authorities, and several federal agencies have asserted federal regulatory authority over certain aspects of the hydraulic fracturing process. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations, and in June 2016 EPA issued final effluent limitations guidelines under the CWA that waste-water from shale natural gas extraction operations must meet before discharging to a publicly owned treatment works. The EPA also issued an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act ("TSCA") in 2014 regarding reporting of the chemical substances and mixtures used in hydraulic fracturing but, to date, has taken no further action. Separately, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, a Wyoming federal court struck down this rule in June 2016. The June 2016 decision was appealed by the BLM to the U.S. Circuit Court of Appeals for the Tenth Circuit. However, following issuance of a presidential executive order to review rules related to the energy industry, in July 2017, the BLM published a notice of proposed rulemaking to rescind the 2015 final rule. In September 2017, the Tenth Circuit issued a ruling to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in light of the BLM's proposed rulemaking. The BLM issued a final rule repealing the 2015 hydraulic fracturing rule in December 2017. The current administration has announced that it intends to review the repeal of the 2015 hydraulic fracturing rule under the *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis.*

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears uncertain. In Texas and New Mexico, specific oil and natural gas regulations apply to oil and gas operations, including the drilling, completion and operations of wells, and the disposal of waste oil and salt water. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency. As an example, the Texas Railroad Commission ("RRC") adopted rules in 2014 requiring companies seeking permits for disposal wells to provide seismic activity data in permit applications. The rules also allow the RRC to modify, suspend, or terminate permits if a disposal well is determined to be causing seismic activity. Determinations by the RRC under these rules may adversely affect our operations. In New Mexico, the Produced Water Act, effective July 1, 2019, governs the discharge, handling, transport, storage, and recycling or treatment of produced water. In January 2021, State Senator Antoinette Sedillo Lopez of New Mexico, introduced a bill which would prohibit certain uses of fresh water in fracking operations, require the disclosure of the chemical composition of produced water from spills, and increase penalties for produced water spills by the oil and gas industry. State Senator Sedillo introduced another bill for the 2021 legislative session seeking to prevent the New Mexico Energy, Minerals and Natural Resources Department from issuing new fracking permits until 2025. Similar legislation was unsuccessful in the 2019 and 2020 legislative sessions. However, if enacted, this legislation would have a material adverse effect on our business and prospects.

Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. In Texas, however, local governments are expressly preempted from regulating oil and gas operations with limited exceptions, under Texas Natural Resources Code Section 81.0523. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the local, state or federal level, our fracturing activities could become subject to additional permit and financial assurance requirements, more stringent construction requirements, increased reporting or plugging and abandoning requirements or operational restrictions and associated permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable and could cause us to incur substantial compliance costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Climate Change

Continuing political and social attention to the issue of global climate change has resulted in both existing and pending international agreements and national, regional or local legislation and regulatory measures to limit or reduce emissions of so-called greenhouse gases ("GHGs"), such as cap and trade regimes, carbon taxes, restrictive permitting, increased fuel efficiency standards and incentives or mandates for renewable energy. In December 2009, the EPA published an endangerment finding concluding that emissions of CO_2, methane and certain other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit requirements for GHG emissions from certain large stationary sources that already are major sources of criteria pollutants under the CAA. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In addition, the EPA has adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities on an annual basis, as well as reporting GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing.

In June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, including implementation of a leak detection and repair ("LDAR") program to minimize methane emissions, under the CAA's New Source Performance Standards in 40 C.F.R. Part 60, Subpart OOOOa ("GHG NSPS"). On April 18, 2017, the EPA announced its intention to reconsider certain aspects of those regulations, and in June 2017, the EPA proposed a two-year stay of certain requirements of the GHG NSPS regulations. In October 2018 the EPA proposed revisions to the GHG NSPS, such as changes to the frequency for monitoring fugitive emissions at well sites and changes to requirements that a professional engineer certify when meeting certain GHG NSPS requirements is technically infeasible. EPA proposed further revisions to the GHG NSPS on September 24, 2019, including rescinding the methane requirements in the GHG NSPS that apply to sources in the production and processing segments of the industry. In September 2020, the EPA finalized amendments to the GHG NSPS that rescind requirements for the transmission and storage segment of the oil and natural gas industry and rescind methane-specific limits that apply to the industry's production and processing segments, among other things. The current administration has announced that it intends to review the September 2020 rules under the *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*, which review may result in the reinstatement of the now-rescinded standards or promulgation of more stringent standards. Our Company has taken measures to control methane leaks, but it is possible that these rules and future revisions thereto will require us to take further methane emission reduction measures, which may require us to expend material sums.

In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and natural gas operations on federal lands that are substantially similar to the GHG NSPS requirements. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule, which became effective on November 27, 2018. Both the 2016 and the 2018 rule were challenged in federal court. On July 21, 2020, a Wyoming federal court vacated almost all of the 2016 rule, including all provisions relating to the loss of gas through venting, flaring, and leaks, and on July 15, 2020, a California federal court vacated the 2018 rule. As a result of these decisions, the 1979 regulations concerning venting, flaring and lost production on federal land have been reinstated. The current administration is likely to impose new regulations on GHG emissions from oil and natural gas production operations on federal land, given the long-term trend towards increasing regulation in this area. Moreover, several states have already adopted rules requiring operators of both new and existing sources to develop and implement an LDAR program and to install devices on certain equipment to capture methane emissions. Compliance with these rules could require us to purchase pollution control and leak detection equipment, and to hire additional personnel to assist with inspection and reporting requirements.

In addition, a number of state and regional efforts are aimed at tracking and/or reducing GHG emissions by means of cap-and-trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measure each country will use to achieve its GHG emissions targets, (the "Paris Agreement"). However, the Paris Agreement does not impose any binding obligations on the United States. In June 2017, President Trump announced that the United States would withdraw from the Paris Agreement, which became effective November 4, 2020. President Biden announced on January 20, 2021 that the United States will rejoin the Paris Agreement. Further, several states, including New Mexico, and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose further restrictions on GHG emissions as a result of the Paris Agreement. The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require additional expenditures to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves. Recently, stakeholders concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Finally, to the extent 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, such events could have a material adverse effect on the Company and potentially subject the Company to further regulation. The trend of more expansive and stringent environmental legislation and regulations, including greenhouse gas regulation, could continue, resulting in increased costs of conducting business and consequently affecting our profitability.

Operational Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, well blow-outs, pipe failures, industrial accidents, and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil releases, chemical releases, natural gas leaks and the discharge of toxic gases.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us, for example, as a result of damage to our property or equipment or injury to our personnel. These operational risks could also result in the spill or release of hazardous materials such as drilling fluids or other chemicals, which may result in pollution, natural resource damages, or other environmental damage and necessitate investigation and remediation costs. As a result, we could be subject to liability under environmental law or common law theories. In addition, these operational risks could result in the suspension or delay of our operations, which could have significant adverse consequences on our business.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. Under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities for environmental matters for which we do not have insurance coverage, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

Human Capital Management

Key to our mission is our employees upon which the foundation of our company is built. We seek to employ the best people who exemplify our core values of honesty and integrity, and are diligent, hard-working individuals who deliver results, and who are good neighbors and contribute to the communities in which they live.

As of December 31, 2020, we had forty-one (41) full-time employees. Our employees are extremely valuable to the success of the company and we encourage their collaboration and respect their diverse points of view and opinions. In addition to our full-time employees, the Company also employs a diverse group of independent contractors who assist our full-time staff in a range of areas including geology, engineering, land, accounting, and field operations, as needed. None are represented by labor unions or covered by any collective bargaining agreements.

Diversity and inclusion: The unique backgrounds and experiences of our employees help to develop a wide range of perspectives that lead to better solutions. Our staff's diversity is reflected in our full-time employees where 22% are women and nearly one third represent minorities. The majority of our employees are citizens of the United States, with a few retaining dual citizenships in other countries. The employees who are not US citizens, are legally registered to live and work here and the Company is committed to helping those employees retain their ability to remain in the US and continue their employment. The Company is also committed to continuously providing an inclusive work environment where all of our employees can be respected, valued, and successful in achieving their goals, all while contributing to the Company's success.

We recognize that attracting, retaining and developing our employees is critical for our future success. Our Executive Vice President of Land, Legal, Human Resources and Marketing, together with our Chief Executive Officer are responsible for developing and executing our human capital strategy, with oversight by the Board of Directors and the Board committees. Some of our key human capital areas of focus include:

Building a Safe Workforce Starts with Our Culture: Ring is committed to building a safety culture that empowers employees and contractors to act as needed to work safely and to stop the job, without retribution, if conditions are deemed unsafe. We strive to be incident-free every day across our operations. We are focused on building and maintaining a safe workplace for all employees and contractors. The oil and gas industry has a number of inherent risks and our workers are often outdoors, in all seasons and all types of weather. In addition, our field personnel spend significant time driving on a daily basis, putting them at risk for driving incidents. A strong safety culture is essential to the Company's success, and we emphasize the important role that all personnel play in creating and maintaining a safe work environment.

Health and Safety Training and Education: We offer a wide range of training opportunities for employees and contractors to help them develop their skills and understanding of our health and safety policy and programs. In addition to teaching specific skills, these training opportunities encourage personal responsibility for safe operating conditions and help to build a culture of individual accountability for conducting job tasks in a safe and responsible manner.

Ring Energy supports both company identified and employee identified educational opportunities for employees to advance in their technical and managerial skills and to help provide opportunities to advance throughout our company. Ring's support comes in the form of full or partial funding of educational programs and opportunities, including time off work to attend and/or prepare for such programs.

COVID-19 Response: Our COVID-19 management plan was built around the need to support all employees in managing their personal and professional challenges. Frequent and transparent communications were the focus at every level of the organization from those on the front lines to those in our corporate offices. During the early stages of the pandemic, Ring's management team directed the Company's overall COVID-19 pandemic response by implementing all relevant county, state and local government guidelines, directives and regulations, and developed and adopted work-from-home provisions and procedures, implemented safe working protocols for production teams, assessed and implemented appropriate return-to-office protocols, and provided timely and transparent communications to employees and key stakeholders.

In response to the COVID-19 pandemic, Ring began providing the following benefits to its employees:

- covering the cost of COVID-19 testing through expanded insurance coverage;
- promoting telehealth benefits;
- promoting mental health and well-being plans;
- providing additional paid sick leave for quarantined employees.

Seasonal Nature of Business

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

Available Information

Our Internet website can be found at www.ringenergy.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act of 1934 will be available through our Internet website free of charge as soon as reasonably practical after we electronically file such material with, or furnish it to, the SEC. The information on, or that can be accessed through, our website is not incorporated by reference into this Annual Report and should not be considered part of this Annual Report. The SEC also maintains an Internet website (http://www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A: Risk Factors

The following risks and uncertainties may affect our performance, results of operations and the trading price of our common stock.

Risks Relating to Our Business, Operations and Strategy

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve additional risks and uncertainties in their application if compared to conventional drilling.

Our operations utilize some of the latest horizontal drilling and completion techniques as developed by us, other oil and natural gas exploration and production companies and our service providers. The additional risks that we face while drilling horizontally include, but are not limited to, the following:

- drilling wells that are significantly longer and/or deeper than wells drilled by others;
- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

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

- the ability to fracture or stimulate the planned number of stages in a horizontal or lateral wellbore;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

If our assessments of purchased properties are materially inaccurate, it could have a significant impact on future operations and earnings.

The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. We plan to undertake further development of our properties through the use of cash flow from existing production. Therefore, a material deviation in our assessments of these factors could result in less cash flow being available for such purposes than we presently anticipate, which could either delay future development operations (and delay the anticipated conversion of reserves into cash) or cause us to seek alternative sources to finance development activities.

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

Our prospects are in various stages of evaluation, ranging from prospects that are currently being drilled to prospects that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. This risk may be enhanced in our situation, due to the fact that a significant percentage (43%) of our proved reserves is currently proved undeveloped reserves. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data obtained by analyzing other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

A substantial percentage of our proved properties are undeveloped; therefore, the risk associated with our success is greater than would be the case if the majority of our properties were categorized as proved developed producing.

Because a substantial percentage of our proved properties are proved undeveloped (approximately 43%), we will require significant additional capital to develop such properties before they may become productive. Further, because of the inherent uncertainties associated with drilling for oil and gas, some of these properties may never be developed to the extent that they result in positive cash flow. Even if we are successful in our development efforts, it could take several years for a significant portion of our undeveloped properties to be converted to positive cash flow.

While our current business plan is to fund the development costs with cash flow from our other producing properties, if such cash flow is not sufficient we may be forced to seek alternative sources for cash, through the issuance of additional equity or debt securities, increased borrowings or other means.

Hedging transactions may limit our potential gains.

To reduce our exposure to commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we may enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production in order to economically hedge a portion of our forecasted oil and natural gas production. Additionally, our credit facility requires us to hedge a portion of our production. In addition, these derivative contracts may limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. As of December 31, 2020, the Company has in place derivative contracts covering 9,000 and 1,750 barrels of oil per day for the calendar years 2021 and 2022, respectively, and covering 6,000 and 5,000 MMBTU of natural gas per day for the calendar years 2021 and 2022, respectively. For 2021, contracts covering 4,500 of the 9,000 barrels of oil are in the form of costless collars of WTI Crude Oil prices. “Costless collars” are the combination of two options, a put option (floor) and a call option (ceiling) with the options structured so that the premium paid for the put option will be offset by the premium received from selling the call option. These collars have floors ranging from $40.00 to $45.00, with an averaged floor of $42.22 and have ceilings ranging between $52.71 and $55.35 per barrel, with an average ceiling of $54.57. The remaining 4,500 barrels of oil in 2021 and all of the 1,750 barrels of oil in 2022 are in the form of swaps of WTI Crude Oil prices. The oil swap prices for 2021 range from $45.00 to $45.96, with an average of $45.42. The oil swap prices for 2022 range from $44.22 to $45.98, with an average of $44.84. All of the contracts for natural gas for both 2021 and 2022 are in the form of swaps of Henry Hub. The swap prices for 2021 and 2022 are $2.991 and $2.7255, respectively.

Hedging transactions may expose us to risk of financial loss.

While intended to reduce the effects of volatile crude oil and natural gas prices, such derivative contracts expose us to risk of financial loss in some circumstances, including when there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received, or when the counterparty to the derivative contract is financially constrained and defaults on its contractual obligations. It is also possible that sales volumes fall below the hedged volumes leaving a portion of our position uncovered.

The phaseout of the London Interbank Offered Rate (LIBOR), or the replacement of LIBOR with a different reference rate, may adversely affect interest rates.

On July 27, 2017, the Financial Conduct Authority (the authority that regulates LIBOR) announced that it would phaseout LIBOR by the end of 2021. It is unclear whether new methods of calculating LIBOR will be established such that it continues to exist after 2021, or if the alternative rates or benchmarks will be adopted. Changes in the method of calculating LIBOR, or the replacement of LIBOR with an alternative rate or benchmark, may adversely affect interest rates and result in higher borrowing costs. This could materially and adversely affect the Company’s results of operations, cash flow and liquidity. We cannot predict the effect of the potential changes to LIBOR or the establishment and use of alternative rates or benchmarks. If changes are made to the method of calculating LIBOR or LIBOR ceases to exist, we may need to amend certain contracts and cannot predict what alternative rate or benchmark would be negotiated. This may result in an increase to our interest expense.

We may be adversely affected by natural disasters, pandemics (including the recent coronavirus outbreak) and other catastrophic events, and by man-made problems such as terrorism, that could disrupt our business operations.

Natural disasters, adverse weather conditions, floods, pandemics (including the recent coronavirus outbreak), acts of terrorism and other catastrophic or geo-political events may cause damage or disruption to our operations and the global economy, or could result in market disruption, any of which could have an adverse effect on our business, operating results, and financial condition.

The ongoing coronavirus outbreak at the beginning of 2020 has impacted various businesses throughout the world, including an impact on the global demand for oil and natural gas, travel restrictions and the extended shutdown of certain businesses in impacted geographic regions. If the coronavirus outbreak situation should worsen, it could have a material adverse impact on our business operations, operating results and financial condition.

The ongoing COVID-19 pandemic, and the relations of and agreements between OPEC+ producers, could disrupt our operations and adversely impact our business and financial results.

The COVID-19 pandemic has led to worldwide shutdowns, reductions in commercial and interpersonal activity, and changes in consumer behavior. In attempting to control the spread of COVID-19, governments around the world imposed regulations such as shelter-in-place orders, quarantines, executive orders and similar restrictions. As a result, the global economy has been marked by significant slowdown and uncertainty, which in turn has led to a precipitous decline in oil prices in response to decreased demand, further exacerbated by the OPEC+ price war during the first quarter 2020 and global storage shortages. The confluence of these events has resulted in a significantly weaker outlook for oil and natural gas producers, including reduced operating and capital budgets as well as diminished market confidence in overall industry viability. While OPEC+ producers have agreed to cut oil production to a limited extent, downward pressure on commodity prices has remained and could continue for the foreseeable future. We currently are unable to predict the duration or severity of the spread of COVID-19 or the adverse effects thereof, including a global economic recession resulting from the pandemic, or the continuance or effectiveness of the OPEC+ voluntary production adjustments (or the terms thereof or compliance therewith). If economic and industry conditions do not improve, these factors will adversely impact our financial condition and results of operations.

The current environment may make it even more difficult to comply with our covenants and other restrictions in our credit facility, and a lack of confidence in our industry on the part of the financial markets may result in one or more of the following, any of which could lead to reduced liquidity: a lack of access to capital; an event of default under our credit facility; the possible acceleration of our repayment of outstanding debt under our credit facility; the exercise of certain remedies by our lenders; or a limited or total inability to refinance our debt.

The loss of key members of management or failure to attract and retain other highly qualified personnel could, in the future, affect the Company's business results.

The Company's success depends on its ability to attract, retain and motivate a highly-skilled and diverse management team and workforce. In the last six months, the Company has experienced significant leadership changes, including appointing a new Chief Executive Officer, Executive Vice President of Operations, a new Executive Vice President of Engineering and Corporate Strategy, a new Vice President of Compliance, a new Executive Vice President of Land, Legal, Human Resources and Marketing along with the appointment of new directors to the Board of Directors. Executive leadership transitions can be difficult to manage and could cause disruption to our business. Failure to ensure that the Company has the depth and breadth of management and personnel with the necessary skill set and experience could impede its ability to deliver growth objectives and execute its operational strategy. As the Company continues to expand, it will need to promote or hire additional staff, and, as a result of increased compensation and benefit mandates, it may be difficult to attract or retain such individuals without incurring significant additional costs.

Risks Relating to the Oil and Natural Gas Industry

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile 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:

- changes in global supply and demand for oil and natural gas, which has recently been negatively affected by concerns about the impact of COVID-19;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the oil price war between Russia and Saudi Arabia;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per BOE basis but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices also negatively impact the value of our proved reserves. The recent drop in the price of oil has forced the Company, as well as other operators, to re-evaluate our current capital expenditure budget and make changes accordingly that we believe are in the best interest of the Company and its stockholders. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. For example, on January 20, 2021, the Biden Administration placed a 60-day moratorium on new oil and gas leasing and drilling permits on federal land, and on January 27, 2021, the Department of Interior acting pursuant to an Executive Order from President Biden suspended the federal oil and gas leasing program indefinitely. While we do not have a significant federal lands acreage position at 240 net acres, these actions could have a material adverse effect on the Company and our industry.

Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. . ." (below) for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following: delays imposed by or resulting from compliance with regulatory requirements; pressure or irregularities in geological formations; shortages of or delays in obtaining equipment and qualified personnel; equipment failures or accidents; adverse weather conditions; reductions in oil and natural gas prices; title problems; and limitations in the market for oil and natural gas.

Decreases in oil and natural gas prices may require us to take write-downs of the carrying values of our oil and natural gas properties which could negatively impact the trading value of our securities.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down could also constitute a non-cash charge to earnings. The cumulative effect of a write-down could also negatively impact the trading price of our securities.

We follow the full cost method of accounting for our oil and natural gas properties. Under the full cost method, the net book value of properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling is the estimated after tax future net revenues from proved oil and natural gas properties, discounted at 10% per year. Discounted future net revenues are estimated using oil and natural gas spot prices based on the average price during the preceding 12-month period determined as an un-weighted, arithmetic average of the first-day-of-the-month price for each month within such period, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an impairment expense. During the year ended December 31, 2020, we recorded a non-cash write down of $277.5 million. We did not record a write down during 2019. Under SEC full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings.

It is difficult to predict with reasonable certainty the amount of expected future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, upward or downward reserve revisions, reserve adds, and tax attributes.

Decreases in oil and natural gas prices may affect our borrowing base, potentially requiring earlier than anticipated debt repayment, which could negatively impact the trading value of our securities.

Decreases in oil and natural gas prices could also result in reductions in the borrowing base of our Credit Facility, thus requiring earlier than anticipated repayment of debt.

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

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

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reported reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reported proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If future values decline or costs increase it could negatively impact our ability to finance operations, and individual properties could cease being commercially viable, affecting our decision to continue operations on producing properties or to attempt to develop properties. All of these factors would have a negative impact on earnings and net income, and most likely the trading price of our securities. These factors could also result in the acceleration of debt repayment and a reduction in our borrowing base under our credit facility.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our Company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could materially and adversely affect us.

Unless we replace our oil and natural gas reserves, our reserves and production will decline as reserves are produced.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. If we are unable to develop, exploit, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

Competition is intense in the oil and natural gas industry.

We operate in a highly competitive environment for acquiring properties and marketing oil and natural gas. Our competitors include multinational oil and natural gas companies, major oil and natural gas companies, independent oil and natural gas companies, individual producers, financial buyers as well as participants in other industries that supply energy and fuel to consumers. Many of our competitors have greater and more diverse resources than we do. Additionally, competition for acquisitions may significantly increase the cost of available properties. We compete for the personnel and equipment required to explore, develop and operate properties. Our competitors also may have established long-term strategic positions and relationships in areas in which we may seek to enter. Consequently, our competitors may be able to address these competitive factors more effectively than we can. If we are not successful in our competition for oil and natural gas reserves or in our marketing of production, then our financial condition and operation results may be adversely affected.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business.

Currently, the majority of our production is sold to marketers and other purchasers that have access to nearby pipeline facilities. However, as we further develop our properties, we may find production in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking or requiring compression facilities. Such restrictions on our ability to sell our oil or natural gas could have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

Risks Relating to Legal, Regulatory, Privacy and Tax Matters

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. It is not possible to predict how or when regulations affecting our operations might change. The Biden Administration's January 20, 2021 issuance of a 60-day moratorium on new oil and gas leasing and drilling permits on federal land, and the related January 27, 2021 Executive Order suspending the federal oil and gas leasing program are examples of the uncertainties our Company and the industry faces with respect to regulation at the federal level. Similarly, at the state level, New Mexico's consideration of legislation to prohibit certain uses of freshwater in fracking operations, implement new disclosure requirements, and increase penalties may affect the cost and feasibility of our business. We may be required to make large expenditures to comply with governmental regulations. Other matters subject to regulation include: discharge permits for drilling operations; drilling bonds; reports concerning operations; the spacing of wells; unitization and pooling of properties; and taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

Our operations may incur substantial liabilities to comply with the environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition as well as the industry in general. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. The amount of additional future costs is not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions or compliance efforts that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

The U.S. Congress and the EPA, in addition to some state and regional authorities, have in recent years considered legislation or regulations to reduce emissions of greenhouse gases, or GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the absence of federal GHG-limiting legislation, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the U.S. CAA. For example, the EPA has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish permitting requirements for GHG, require that certain facilities meet "best available control technology" standards, and mandate annual reporting of GHG emissions.

The EPA also sought to address climate change through its GHG NSPS regulations, which the current administration intends to review, pursuant to the Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis. Many state governments have established rules aimed at reducing greenhouse gas emissions, including greenhouse gas cap and trade programs. Most of these cap-and-trade programs work by requiring major sources of emissions to acquire and surrender emission allowances. It is difficult to predict the timing and certainty of such government actions and their ultimate effect, which could depend on, among other things, the type and extent of greenhouse gas reductions required, the availability and price of emissions allowances or credits, the availability and price of alternative fuel sources, the energy sectors covered, and the ability to recover the costs incurred through our operating agreements or the pricing of oil, natural gas, and other products.

On an international level, the United States is one of almost 200 nations that agreed in December 2015 to the Paris Agreement. However, the Paris Agreement does not impose any binding obligations on the United States. In June 2017, President Trump announced that the United States would withdraw from the Paris Agreement, which became effective November 4, 2020. President Biden announced on January 20, 2021 that the United States will rejoin the Paris Agreement. Further, several states, including New Mexico, and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the Paris Agreement.

Risks Relating to Our Capital Structure

If our indebtedness increases, it could reduce our financial flexibility.

We have a credit facility in place with $350 million in commitments for borrowings and letters of credit. As of December 31, 2020, $313 million was outstanding on our credit facility. If we further utilize this facility, the level of our indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flow could be used to service the indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in our credit facility limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments, and;
- a high level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

In addition, our bank borrowing base is subject to semi-annual redeterminations. We could be required to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are required to do so, we may not have sufficient funds to make such repayments, and we may need to negotiate renewals of our borrowings or arrange new financing or sell significant assets. Any such actions could have a material adverse effect on our business and financial results.

We may be unable to access the equity or debt capital markets to meet our obligations.

Our plans for growth may include accessing the capital markets. Recent reluctance to invest in the exploration and production sector based on market volatility, perceived underperformance and Environmental, Social and Governance (ESG) trends, among other things, has raised concerns regarding capital availability for the sector. If those markets are unavailable, or if we are unable to access alternative means of financing on acceptable terms, we may be unable to implement all of our development plans, make acquisitions or otherwise carry out our business strategy, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Risks Relating to Technology and Cybersecurity

We rely on computer and telecommunications systems, and failures in our systems or cyber security attacks or breaches could result in information theft, data corruption, disruption in operations and/or financial loss.

The oil and natural gas industry has become increasingly dependent upon digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, process and store personally identifiable information on our employees and royalty owners and communicate with our employees and other third parties. Our business partners, including vendors, service providers, purchasers of our production and financial institutions, are also dependent on digital technology. It is possible that we could incur interruptions from cyber security attacks or breaches, computer viruses or malware that could result in disruption of our business operations and/or financial loss. Although we utilize various procedures and controls to monitor and protect against these threats and 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 and causing us to suffer losses in the future. Even so, any cyber incidents or interruptions to our computing and communications infrastructure or our information systems could lead to data corruption, communication interruption, unauthorized release, gathering, monitoring, misuse or destruction of proprietary or other information, or otherwise significantly disrupt our business operations. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Relating to Our Common Stock

The market price of our common stock may be volatile, which could cause the value of your investment to decline.

The stock markets have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. The market price of our common stock may also fluctuate significantly in response to the following factors, some of which are beyond our control:

- our operating and financial performance and prospects;
- variations in our quarterly operating results and changes in our liquidity position;
- investor perceptions of us and the industry and markets in which we operate;
- future sales, or the availability for sale, of equity or equity-related securities;
- changes in securities analysts' estimates of our financial performance;
- changes in market valuations of similar companies;
- changes in the price of oil and natural gas; and
- general financial, domestic, economic and other market conditions.

We have no current plans to pay dividends on our common stock.

We do not currently anticipate paying any cash dividends on our common stock. We currently intend to retain future earnings, if any, to pay down debt and finance the expansion of our business. Our future dividend policy is within the discretion of our Board of Directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, our current credit facility prohibits us from paying dividends.

Our Board of Directors can, without stockholder approval, cause preferred stock to be issued on terms that could adversely affect common stockholders.

Under our Articles of Incorporation, our Board of Directors is authorized to issue up to 50,000,000 shares of preferred stock, of which none are issued and outstanding as of the date of this Annual Report. Also, our Board of Directors, without stockholder approval, may determine the price, rights, preferences, privileges and restrictions, including voting rights, of those shares. If the Board of Directors causes shares of preferred stock to be issued, the rights of the holders of our common stock could be adversely affected. The Board of Director’s ability to determine the terms of preferred stock and to cause its issuance, while providing desirable flexibility in connection with possible acquisitions and other corporate purposes, could have the effect of making it more difficult for a third party to acquire a majority of our outstanding voting stock. Preferred shares issued by the Board of Directors could include voting rights, or even super voting rights, which could shift the ability to control the Company to the holders of the preferred stock. Preferred shares could also have conversion rights into shares of common stock at a discount to the market price of the common stock which could negatively affect the market for our common stock. In addition, preferred shares would have preference in the event of liquidation of the Company, which means that the holders of preferred shares would be entitled to receive the net assets of the Company distributed in liquidation before the common stockholders receive any distribution of the liquidated assets. We have no current plans to issue any shares of preferred stock.

Provisions under Nevada law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

In addition to the ability of the Board of Directors to issue preferred stock, the existence of some provisions under Nevada law could delay or prevent a change in control of the Company, which could adversely affect the price of our common stock. Nevada law imposes some restrictions on mergers and other business combinations between us and any holder of 10% or more of our outstanding common stock.

Item 1B: Unresolved Staff Comments

None.

Item 2: Properties

General Background

Ring is currently engaged in oil and natural gas acquisition, exploration, development and production, with activities and operations currently in Texas and New Mexico. While our business model includes pursuing acquisition opportunities, our near-term focus will be on the development of our existing properties.

Management's Business Strategy Related to Properties

Our goal is to increase stockholder value by investing in oil and natural gas projects with attractive rates of return on capital employed. We plan to achieve this goal by exploiting and developing our existing oil and natural gas properties and pursuing strategic acquisitions of additional properties.

Developing and Exploiting Existing Properties

We believe that there is significant value to be created by drilling the identified undeveloped opportunities on our properties. As of December 31, 2020, we owned interests in a total of 53,912 gross (45,053 net) developed acres and operate the vast majority of our acreage position. In addition, as of December 31, 2020, we owned interests in approximately 50,543 gross (31,692 net) undeveloped acres. While our near-term plans are focused towards drilling wells on our existing acreage to develop the potential contained therein, our long term plans also include continuing to evaluate acquisition and leasing opportunities.

Pursuing Profitable Acquisitions

We have historically pursued acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have developed and refined an acquisition program designed to increase reserves and complement our existing core properties. We have an experienced team of management and engineering professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties.

Summary of Oil and Natural Gas Properties and Projects

Significant Operations

Northwest Shelf –Yoakum, Runnels and Coke County, Texas and Lea County, New Mexico – In 2019, we acquired properties consisting of 49,754 gross (38,230 net) acres with an average working interest of 77% and an average net revenue interest of 58%. As of December 31, 2020, our acreage position in these counties is 46,972 gross (32,915 net) acres with 11,723 gross (8,085 net) developed and held by production and 35,249 gross (24,830 net) being undeveloped. Our reserve estimates include 72 identified proved horizontal drilling locations and 11 proved vertical drilling locations. Our reserve estimates include the capital costs required to develop these wells. We believe the Northwest Shelf leases contain a considerable number of remaining potential drilling locations.

Central Basin Platform - Andrews and Gaines County, Texas leases – In 2011, we acquired a 100% working interest and a 75% net revenue interest in the Company's initial leases in Andrews and Gaines counties. Since that time, we have acquired working and net revenue interests in additional producing leases and acquired additional undeveloped acreage in and around our Andrews County and Gaines county leases. The working interests range from 1-100% and the net revenue interests range from 1-80%. In total as of December 31, 2020, we own 38,714 gross (25,362 net), acres with 23,668 gross (18,712 net) acres developed and held by production and the remaining 15,046 gross (6,650 net) acres being undeveloped. Our reserve estimates include 2 proved vertical and 32 horizontal PUD wells. Our reserve estimates include the capital costs required to develop these wells. We believe the Central Basin Platform leases contain a considerable number of remaining potential drilling locations.

Delaware Basin - Culberson and Reeves County, Texas leases– In 2015, we acquired properties consisting of 19,983 gross (19,679 net) acres with an average working interest of 98% and an average net revenue interest of 79%. Since that time, we have acquired additional undeveloped acreage in and around our Culberson and Reeves County leases. In total as of December 31, 2020, we own 18,769 gross (18,468 net) acres with 18,521 gross (18,256 net) acres developed and held by production and the remaining 248 gross (212 net) acres being undeveloped. Our reserve estimates include 26 proved vertical and 4 horizontal PUD wells. Our reserve estimates include the capital costs required to develop these wells. We believe the Delaware Basin leases contain a considerable number of remaining potential drilling locations.

Title to Properties

We generally conduct a preliminary title examination prior to the acquisition of properties or leasehold interests. Prior to commencement of operations on such acreage, a thorough title examination is usually conducted and any significant defects are remedied before proceeding with operations. We believe the title to our leasehold properties is good, defensible and customary with practices in the oil and natural gas industry, subject to such exceptions that we believe do not materially detract from the use of such properties. With respect to our properties of which we are not the record owner, we rely on contracts with the owner or operator of the property or assignment of leases, pursuant to which, among other things, we generally have the right to have our interest placed on record.

Our properties are generally subject to royalty, overriding royalty and other interests customary in the industry, liens incident to agreements, current taxes and other customary burdens, minor encumbrances, easements and restrictions. We do not believe any of these burdens will materially interfere with our use of these properties.

Summary of Oil and Natural Gas Reserves

As of December 31, 2020, our estimated proved reserves had a pre-tax PV10 value of approximately $638.1 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $555.9 million, 100% of which relates to our properties in the Permian Basin in Texas and New Mexico. We spent approximately $466.9 million on acquisitions and capital projects during 2019 and 2020. We expect to further develop these properties through additional drilling.

The following table summarizes our total net proved reserves, pre-tax PV10 value and Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2020. All of our reserves are in the Permian Basin in the States of Texas and New Mexico.

Oil (Bbl)	Natural Gas (Mcf)	Total (Boe)	Pre-Tax PV10 Value	Standardized Measure of Discounted Future Net Cash Flows
66,264,286	61,305,027	76,481,791	$ 638,107,637	$ 555,871,253

The Company presents the pre-tax PV10 value, which is a non-GAAP financial measure, because it is a widely used industry standard which we believe is useful to those who may review this Annual Report when comparing our asset base and performance to other comparable oil and natural gas exploration and production companies.

Reserve Quantity Information

Our estimates of proved reserves and related valuations are based on reports independently determined and prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. These reserves are attributable solely to properties within the United States. A summary of the changes in quantities of proved (developed and undeveloped) oil and natural gas reserves is shown below.

	Oil (Bbl)	Gas (Mcf)
Balance, December 31, 2018	27,809,748	52,765,698
Purchase of minerals in place	36,501,824	41,921,368
Improved recovery	4,732,449	2,530,636
Extensions and discoveries	13,295,301	5,501,627
Production	(3,536,126)	(2,476,472)
Sales of minerals in place	(758,169)	(811,279)
Upward revisions of estimates	2,731,228	1,618,234
Downward revision of estimates due to well performance	(3,699,908)	(11,680,453)
Downward revision of estimates due to commodity prices	(3,655,679)	(28,789,545)
Downward revision of estimates due to removal of undeveloped locations	(2,061,654)	(2,307,932)
Balance, December 31, 2019	71,359,014	58,271,882
Improved recovery	3,495,210	1,824,310
Production	(2,801,528)	(2,494,501)
Upward revisions of estimates	2,591,965	6,158,076
Downward revision of estimates due to well performance	(4,484,425)	44,370
Downward revision of estimates due to commodity prices	(2,313,890)	(2,303,700)
Downward revision of estimates due to removal of undeveloped locations	(1,582,060)	(195,410)
Balance, December 31, 2020	66,264,286	61,305,027

Our proved oil and natural gas reserves are shown below.

	For the Years Ended December 31, 2020	2019
Oil (Bbls)		
Developed	38,260,638	41,242,064
Undeveloped	28,003,648	30,116,950
Total	66,264,286	71,359,014
Natural Gas (Mcf)		
Developed	34,335,520	34,467,868
Undeveloped	26,969,507	23,804,014
Total	61,305,027	58,271,882
Total (Boe)		
Developed	43,983,225	46,986,709
Undeveloped	32,498,566	34,084,285
Total	76,481,791	81,070,994

Standardized Measure of Discounted Future Net Cash Flows

Our standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and changes in the standardized measure as described below were prepared in accordance with generally accepted accounting principles.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of our oil and natural gas properties.

Our estimates of reserves and future cash flow as of December 31, 2020 and 2019 were prepared using an average price equal to the unweighted arithmetic average of the first day of the month price for each month within the 12-month periods ended December 31, 2020 and 2019, respectively, in accordance with SEC guidelines. As of December 31, 2020, our reserves are based on an SEC average price of $36.04 per Bbl of WTI oil posted and $1.99 per MMBtu Henry Hub natural gas. As of December 31, 2019, our reserves are based on an SEC average price of $52.19 per Bbl of WTI oil posted and $2.58 per MMBtu Henry Hub natural gas. Prices are adjusted by local field and lease level differentials and are held constant for life of reserves in accordance with SEC guidelines.

The standardized measure of discounted future net cash flows relating to the proved oil and natural gas reserves are shown below.

Standardized Measure of Discounted Future Net Cash Flows

December 31,	**2020**	**2019**
Future cash flows	$ 2,682,488,655	$ 3,825,773,515
Future production costs	(821,515,126)	(964,887,856)
Future development costs	(244,323,270)	(252,457,833)
Future income taxes	(208,645,934)	(424,715,966)
Future net cash flows	1,408,004,325	2,183,711,860
10% annual discount for estimated timing of cash flows	(852,133,072)	(1,260,536,809)
Standardized Measure of Discounted Future Net Cash Flows	$ 555,871,253	$ 923,175,051

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The changes in the standardized measure of discounted future net cash flows relating to the proved oil and natural gas reserves are shown below.

	2020	2019
Beginning of the year	$ 923,175,051	$ 455,944,641
Purchase of minerals in place	—	598,489,190
Improved recovery, less related costs	61,303,074	86,989,301
Extensions and discoveries, less related costs	—	247,652,632
Development costs incurred during the year	29,916,746	152,125,320
Sales of oil and gas produced, net of production costs	(70,634,853)	(137,663,314)
Sales of minerals in place	—	(30,174,528)
Accretion of discount	92,838,323	47,463,292
Net changes in price and production costs	(368,974,767)	(219,608,128)
Net change in estimated future development costs	(3,883,985)	47,617,158
Upward revisions	32,920,723	44,034,636
Revision of previous quantity estimates as a result well performance	(52,731,122)	(64,553,979)
Revision of previous quantity estimates as a result of commodity prices	(26,590,142)	(71,545,320)
Revision of previous quantity estimates as a result removal of uneconomic proved undeveloped locations	(19,812,745)	(34,079,006)
Revision of estimated timing of cash flows	(139,039,115)	(107,443,484)
Net change in income taxes	97,384,365	(92,073,360)
End of the Year	$ 555,871,553	$ 923,175,051

Our proved reserves by state as of December 31, 2020 are summarized in the table below.

	Oil (Bbl)	Gas (Mcf)	Total (Boe)	% of Total Proved	Pre-tax PV10 (In thousands)	Standardized Measure of Discounted Future Net Cash Flows (In thousands)	Future Capital Expenditures (In thousands)
Texas							
PD	36,075,577	32,364,426	41,469,648	54 %	$ 418,844	$ 364,435	$ 23,655
PUD	27,055,299	26,207,571	31,423,228	41 %	193,527	168,387	208,590
Total Proved:	63,130,876	58,571,997	72,892,876	95 %	$ 612,371	$ 532,822	$ 232,245
New Mexico							
PD	2,185,061	1,971,094	2,513,577	3 %	$ 19,364	$ 17,342	$ 1,505
PUD	948,349	761,936	1,075,338	1 %	6,373	5,707	10,573
Total Proved:	3,133,410	2,733,030	3,588,915	5 %	$ 25,737	$ 23,049	$ 12,078
Total							
PD	38,260,638	34,335,520	43,983,225	57.5 %	$ 438,208	$ 381,777	$ 25,160
PUD	28,003,648	26,969,507	32,498,566	42.5 %	199,900	174,094	219,163
Total Proved:	66,264,286	61,305,027	76,481,791	100 %	$ 638,108	$ 555,871	$ 244,323
	66,264,286	61,305,027	76,481,791		638,108		244,323

Proved Reserves

We have approximately 76.5 million BOE of proved reserves, consisting of approximately 87% oil and 13% natural gas, as summarized in the table above as of December 31, 2020, on a net pre-tax PV10 value and Standardized Measure of Discounted Future Net Cash Flows basis. Our reserve estimates have not been filed with any Federal authority or agency (other than the SEC).

As of December 31, 2020, approximately 57.5% of the proved reserves have been classified as proved developed, or "PD" and the remaining 42.5% are proved undeveloped, or "PUD".

As of December 31, 2020, our total proved reserves had a net pre-tax PV10 value of approximately $638.1 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $555.9 million. Approximately $438.2 million and $381.8 million, respectively, of total proved reserves are associated with the PD reserves, which is approximately 69% of the total proved reserves' pre-tax PV10 value. The remaining $199.9 million and $174.1 million, respectively, are associated with PUD reserves.

Proved Undeveloped Reserves

Our reserve estimates as of December 31, 2020 include approximately 32.5 million BOE as proved undeveloped reserves. As of December 31, 2019, our reserve estimates included approximately 35.1 million BOE as proved undeveloped reserves. Below is a description of the changes in our PUD reserves from December 31, 2019 to December 31, 2020.

During the year ended December 31, 2020, we incurred costs of approximately $10.0 million to convert 1,698,122 BOE of reserves from PUD to PD through development.

Other changes to our PUD reserves included:

- Upward revisions of 3,521,992 BOE as the result of a reduction in lease operating expenses in certain areas and improved offsetting production due to pump optimization and improved completion practices;
- Downward revisions of 1,794,900 BOE as the result of changes in commodity prices; and
- Downward revision of 1,614,628 BOE for the removal of locations due to lack of development within the prescribed time frame due to changes in anticipated development programs as a result of market conditions

The following table indicates projected reserves that we currently estimate will be converted from proved undeveloped to proved developed, as well as the estimated costs per year involved in such development.

Estimated Costs Related to Conversion of Proved Undeveloped Reserves to Proved Developed Reserves

Year	Estimated Oil Reserves Developed (Bbls)	Estimated Gas Reserves Developed (Mcf)	Total Boe	Estimated Development Costs
2021	5,880,319	6,006,939	6,881,476	42,156,847
2022	9,345,510	9,186,059	10,876,520	72,617,289
2023	9,706,829	10,062,460	11,383,906	78,041,149
2024	3,070,990	1,714,049	3,356,665	26,348,548
	28,003,648	26,969,507	32,498,566	$ 219,163,833

Preparation and Internal Controls Over Reserves Estimates

All the proved oil and natural gas reserves disclosed in this report are based on reserve estimates determined and prepared by independent reserve engineers Cawley, Gillespie & Associates ("CGA"), a leader of petroleum property analysis for industry and financial institutions. CGA was founded in 1960 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated February 10, 2021, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

The proved oil and natural gas reserves disclosed in this report are based on reserve estimates determined and prepared by independent reserve engineers primarily using decline curve analysis to determine the reserves of individual producing wells. To establish reasonable certainty with respect to our estimated proved reserves, the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using volumetric estimates or performance from analogous wells in the surrounding area. These wells were considered to be analogous based on production performance from the same formation and completions using similar techniques. The technologies and economic data used to estimate our proved reserves include, but are not limited to, well logs, geological maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. This data was reviewed by various levels of management for accuracy before consultation with independent reserve engineers. This consultation included review of properties, assumptions and available data. Internal reserve estimates were compared to those prepared by independent reserve engineers to test the estimates and conclusions before the reserves were included in this report. The accuracy of the reserve estimates is dependent on many factors, including the following:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future costs, which could vary considerably from actual costs;
- the accuracy of economic assumptions; and
- the judgment of the personnel preparing the estimates.

Ring’s Executive Vice President of Engineering and Corporate Strategy, Mr. Alex Dyes, is the technical professional primarily responsible for overseeing the preparation of our reserves estimates. He has a Bachelor of Science degree in Petroleum Engineering with over 14 years of practical industry experience, including over 10 years of estimating and evaluating reserve information. He is a member of the Society of Petroleum Engineers since 2013 and his qualifications meet or exceed the Society of Petroleum Engineers’ standard requirements to be a professionally qualified Reserve Estimator and Auditor.

We encourage ongoing professional education for our engineers and analysts on new technologies and industry advancements as well as refresher training on basic skill sets. In order to ensure the reliability of reserves estimates, the Corporate Reserves department follows comprehensive SEC-compliant internal controls and policies to determine, estimate and report proved reserves including:

- confirming that we include reserves estimates for all properties owned and that they are based upon proper working and net revenue interests;
- ensuring the information provided by other departments within the Company such as Accounting is accurate;
- communicating, collaborating, and analyzing with technical personnel in our business units;
- comparing and reconciling the internally generated reserves estimates to those prepared by third parties;
- utilizing experienced reservoir engineers or those under their direct supervision to prepare reserve estimates; and
- ensuring compensation for the reserve engineers is not tied to the amount of reserves recorded.

Each quarter, the Executive Vice President of Engineering and Corporate Strategy presents the status of the Company’s reserves to senior executives, and subsequently obtains approval of significant changes from key executives. Additionally, the five-year PUD development plan is reviewed and approved annually by the Company’s Chief Executive Officer, Chief Financial Officer, Executive Vice President of Operations, the Executive Vice President of Land, Legal, Human Resources, and Marketing, and the Executive Vice President of Engineering and Corporate Strategy.

The Corporate Reserves department works closely with independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserves estimates are presented to the Audit Committee. In addition to reviewing the independently developed reserve reports, the Audit Committee also periodically meets with the independent petroleum consultants that prepare estimates of proved reserves.

Summary of Oil and Natural Gas Properties and Projects

Production Summary

Our estimated average daily total Company net production for the month of December 2020 is 9,201 BOE/d. The following table provides the calculation of this daily production rate for the month of December 2020.

Oil (Bbls)	244,857
Gas (Mcf)	242,180
Total production (BOE)	285,221
Daily production (Boe/d)	9,201

Acreage

The following table summarizes gross and net developed and undeveloped acreage as of December 31, 2020 by region (net acreage is our percentage ownership of gross acreage). Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	23,668	18,712	15,046	6,650	38,714	25,362
Delaware Basin	18,521	18,256	248	212	18,769	18,468
Northwest Shelf	11,723	8,085	35,249	24,830	46,972	32,915
Total	53,912	45,053	50,543	31,692	104,455	76,745

Leases of undeveloped acreage will generally expire at the end of their respective primary terms unless production from such leasehold acreage has been established prior to expiration of such primary term. If production is established on such acreage, the lease will generally remain in effect until the cessation of production from such acreage and is referred to in the industry as “Held-By-Production” or “HBP.” Leases of undeveloped acreage may terminate or expire as a result of not meeting certain drilling commitments, if any, or otherwise by not complying with the terms of a lease depending on the specific terms that are negotiated between lessor and lessee.

The following table sets forth the gross and net undeveloped acreage, as of December 31, 2020, under lease which would expire over the next three years unless (i) production is established on the lease or within a spacing unit of which the lease is participating, or (ii) the lease is renewed or extended prior to the relevant expiration dates:

	2021		2022		2023	
	Gross	Net	Gross	Net	Gross	Net
Undeveloped acreage	19,350	13,252	6,409	2,259	1,978	1,908

Production History

The following table presents the historical information about our produced natural gas and oil volumes for the years ended December 31, 2020, 2019 and 2018:

	Years Ended December 31,		
	2020	2019	2018
Oil (Bbls)			
Central Basin Platform	958,691	1,590,473	1,812,616
Delaware Basin	159,635	275,080	234,679
Northwest Shelf	1,683,202	1,670,573	—
Total	2,801,528	3,536,126	2,047,295
Gas (Mcf)			
Central Basin Platform	268,495	315,228	346,115
Delaware Basin	468,177	939,437	766,062
Northwest Shelf	1,757,830	1,221,807	—
Total	2,494,502	2,476,472	1,112,177
Total production (BOE)			
Central Basin Platform	1,003,440	1,643,011	1,870,302
Delaware Basin	237,665	431,653	362,356
Northwest Shelf	1,976,173	1,874,207	—
Total	3,217,278	3,948,871	2,232,658
Daily production (Boe/d)			
Central Basin Platform	2,742	4,501	5,124
Delaware Basin	649	1,183	993
Northwest Shelf	5,399	5,135	—
Total	8,790	10,819	6,117

Production Prices and Production Costs

The following tables provides historical pricing and costs statistics for the years ended December 31, 2018, 2019 and 2020.

	Years Ended December 31,		
	2020	2019	2018
Average sales price:			
Oil (per Bbl)	$ 38.95	$ 54.27	$ 56.99
Natural gas (per Mcf)	1.57	1.54	3.05
Total (per Boe)	35.13	49.56	53.78
Average production cost (including ad valorem taxes) (per Boe)	$ 11.49	$ 12.28	$ 12.45
Average production taxes (per Boe)	1.63	2.31	2.52

The average oil sales price amounts above are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels “Bbl”. The average natural gas sales price amounts above are calculated by dividing revenue from natural gas sales by the volume of natural gas sold, in thousand cubic feet “Mcf”. The total average sales price amounts are calculated by dividing total revenues by total volume sold, in BOE. The average production costs above are calculated by dividing production costs by total production in BOE.

Productive Wells

The following table presents our ownership as of December 31, 2020 in productive oil and natural gas wells (a net well is our percentage ownership of a gross well). All of such wells are in the Permian Basin in Texas and New Mexico.

Oil Wells		Gas wells		Total Wells	
Gross	Net	Gross	Net	Gross	Net
610	441	—	—	610	441

Drilling Activity

During 2020, we drilled 6 gross (5.61 net) wells in the Northwest Shelf in the Permian Basin. We completed and placed on production 4 of these wells during the first quarter 2020. Two wells were drilled in December 2020 and subsequently completed and placed on production during 2021. All of these wells were successful and there were no dry wells.

The table below contains information regarding the number of wells drilled during the periods indicated.

	For the year ended December 31,					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development						
Productive	6.00	5.61	30.00	29.33	57.00	56.25
Dry						
Total						
Productive	6.00	5.61	30.00	29.33	57.00	56.25
Dry	—	—	—	—	—	—

Present Activities

There were no wells in the process of being drilled, however, there were two wells waiting to be being completed as of December 31, 2020.

Cost Information

We conduct our oil and natural gas activities entirely in the United States. As noted in the table under “Production Prices and Production Costs”, our average production costs, per BOE, were $12.45, $12.28 and $11.49 during the years ended December 31, 2018, 2019 and 2020, respectively, and our average production taxes, per BOE, were $2.52, $2.31 and $1.63 for the years ended December 31, 2018, 2019 and 2020, respectively. These amounts are calculated by dividing our total production costs or total production taxes by our total volume sold, in BOE.

Costs incurred for property acquisition, exploration and development activities during the years ended December 31, 2019 and 2020 are shown below:

	2020	2019
Wishbone Acquisition (1)	$ —	$ 304,392,921
Acquisition of proved properties	1,317,313	3,400,411
Divestiture of proved properties	—	(8,547,074)
Acquisition of unproved properties	—	—
Exploration costs	—	—
Development costs	42,457,745	152,125,320
Total Costs Incurred	$ 43,775,058	$ 451,371,578

(1) Wishbone Acquisition in 2019 includes $28.3 million in fair value of stock issued as consideration in acquisitions.

Other Properties and Commitments

Our principal executive offices are in leased office space in The Woodlands, Texas. The lease for this office space was entered into subsequent to December 31, 2020. Prior to this and throughout 2020, our principal offices were in Midland, Texas. Those offices now serve as an operations office. We also lease office space in Tulsa, Oklahoma, which serves as our current accounting office, but which will be closed following the transition of those functions to The Woodlands offices. We expect our current office space to be adequate as we move forward.

Item 3: Legal Proceedings

In the ordinary course of business, we may be, from time to time, a claimant or a defendant in various legal proceedings. We do not presently have any material litigation pending or threatened requiring disclosure under this item.

Item 4: Mine safety disclosures

Not applicable.

PART II

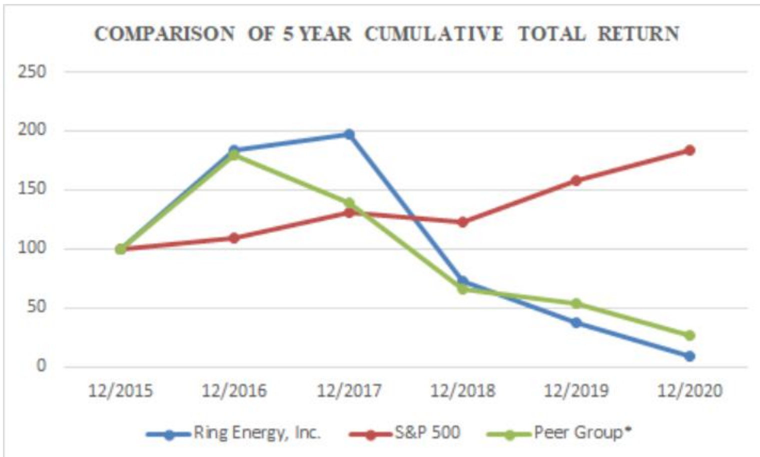
Item 5: Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for our Common Stock

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

Performance Graph

The following graph compares the cumulative 5-year total return attained by stockholders on Ring's common stock relative to the cumulative total returns of the S&P 500 index and that of a selected peer group, named below. The graph assumes a $100 investment at the closing price on December 31, 2015, and reinvestment of dividends on the date of payment without commission. This table is not intended to forecast future performance of our common stock.



* The peer group consists of: Callon Petroleum Company, Earthstone Energy, Inc., Laredo Petroleum, Inc., Abraxas Petroleum Corporation and Contango Oil & Gas Company, all of which are in the oil and natural gas exploration and production industry.

The performance graph above is furnished and not filed for purposes of Section 18 of the Exchange Acts and will not be incorporated by reference into any registration filed under the Securities Act unless specifically identified therein as being incorporated by reference. The performance graph is not solicitation material subject to Regulation 14A.

Record Holders

As of March 1, 2021, there are approximately 21,632 holders of record of our common stock.

Dividend Policy

We do not currently anticipate paying any cash dividends on our common stock. We currently intend to retain future earnings, if any, to pay down debt and finance the expansion of our business. Our future dividend policy is within the discretion of our Board of Directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, our current credit facility prohibits us from paying dividends.

Recent Sales of Unregistered Securities and Use of Proceeds from Registered Securities

None

Issuer Repurchases

We did not make any repurchases of our equity securities during the year ending December 31, 2020.

Item 6: Selected Financial Data

The selected financial information set forth below is derived from our balance sheets and statements of operations as of and for the years ended December 31, 2020, 2019, 2018, 2017 and 2016. The data set forth below should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and related notes thereto included in this Annual Report.

	For the years ended December 31,				
	2020	2019	2018	2017	2016
Statement of Operations Data:					
Revenues	$ 113,025,138	$ 195,702,831	$ 120,065,361	$ 66,699,700	$ 30,850,248
Cost of revenues	42,196,963	57,626,604	33,433,082	19,130,924	11,372,420
Depreciation, depletion and amortization	43,010,660	56,204,269	39,024,886	20,517,780	11,483,314
Ceiling test impairment	277,501,943	—	14,172,309	—	56,513,016
Accretion	906,616	943,707	606,459	567,968	487,182
Operating lease expense	1,196,372	925,217	—	—	—
General and administrative	16,874,050	19,866,706	12,867,686	10,515,887	8,027,077
Net income (loss)	(253,411,828)	29,496,551	8,999,760	1,753,869	(37,637,687)
Basic income (loss) per common share	$ 3.48	$ 0.44	$ 0.15	$ 0.03	$ (0.97)
Diluted income (loss) per common share	$ 3.48	$ 0.44	$ 0.15	$ 0.03	$ (0.97)

	As of December 31,				
	2020	2019	2018	2017	2016
Balance Sheet Data:					
Current assets	$ 20,799,890	$ 38,708,541	$ 16,844,257	$ 29,123,924	$ 75,220,915
Oil and gas properties subject to amortization	836,514,815	1,083,966,135	641,121,398	433,591,134	250,133,965
Total assets	663,456,197	973,006,148	567,065,659	414,102,486	307,597,399
Total current liabilities	36,941,737	59,092,554	51,910,432	48,443,449	9,099,391
Total long-term liabilities	331,748,647	390,403,661	52,555,797	9,055,697	7,957,035
Total Stockholders Equity	294,765,813	523,509,933	462,599,430	356,603,340	290,540,973

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 accompanying financial statements and the notes to those financial statements included elsewhere in this Annual Report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs and our actual results could differ materially from those discussed in these forward-looking statements as a result of many factors, including those discussed under "Risk Factors" and elsewhere in this Annual Report.

Overview

Ring is an exploration and production company based in The Woodlands that is engaged in oil and natural gas acquisition, exploration, development and production activities. Our exploration and production interests are currently focused in Texas and New Mexico. The Company seeks to exploit its acreage position through the drilling of highly economic, vertical and horizontal wells using the most recent drilling and completion techniques. Our focus is drilling and developing our oil and gas properties through use of cash flow generated by our operations and reducing our long-term debt through the sale of non-core assets or through our excess cash flow while still working towards providing annual production growth. We continue to evaluate potential transactions to acquire attractive acreage positions within our core areas of interest.

Business Description and Plan of Operation

The Company seeks to exploit its acreage position through the drilling of highly economic, vertical and horizontal wells using the most recent drilling and completion techniques. Our focus is drilling and developing our oil and gas properties through use of cash flow generated by our operations and reducing our long-term debt through the sale of non-core assets or through our excess cash flow while still working towards maintaining or providing annual production growth. We continue to evaluate potential transactions to acquire attractive acreage positions within our core areas of interest.

2020 Developments and Highlights

In March 2020, the World Health Organization declared the COVID-19 outbreak a pandemic. Governments have tried to slow the spread of the virus by imposing social distancing guidelines, travel restrictions and stay-at-home orders, which have caused a significant contraction in global economic activity, including a decline in the demand for oil and to a lesser extent natural gas.

Our business and operations have been adversely affected by, and may continue to be adversely affected by, the COVID-19 pandemic and the public health response thereto. As a result of the COVID-19 outbreak and the adverse public health developments, including voluntary and mandatory quarantines, travel restrictions and other restrictions, our operations, and those of our subcontractors, customers and suppliers, have experienced, and may to continue to experience, delays or disruptions. Starting the last week of April, essentially all of our production, other than that associated with our Delaware Basin property, was shut-in or curtailed. The curtailments continued until early June, when, with commodity prices improving and price differentials decreasing, the Company began to bring wells back on-line, returning to near April levels by the end of the second quarter. In the third quarter 2020, we had restored production to 9,549 net BOEPD and in the fourth quarter 2020 we produced 9,307 net BOEPD.

In addition, our financial condition and results of operations have been, and may continue to be, adversely affected by the ongoing coronavirus outbreak. The timeline and potential magnitude of the COVID-19 outbreak and its consequences are currently unknown. The prolongation or exacerbation of this pandemic could more extensively affect the United States and global economy, including the demand for oil and natural gas.

The Company has experienced the effects of a negatively impacted domestic and international demand for crude oil and natural gas, which has contributed to price volatility and impacted the price we received for our production, and moreover materially and adversely affected the demand for and marketability of our production. For the Company, this means that production was shut in for some of our wells, and that we held some of our production as inventory to be sold at a later date because we refused to accept the unprecedented and exceptionally low price for our production. Our 2020 first quarter results were negatively impacted by the pandemic response, and we continued to experience the pandemic's negative impact through the fourth quarter of 2020. At this time, we expect that our financial results for the first quarter of 2021 may be adversely impacted by our response to, the existence of and the global response to the COVID-19 pandemic.

Also, in March 2020, Saudi Arabia and Russia, along with OPEC producers, failed to agree to cut oil production, and Saudi Arabia significantly cut the sell price of its oil and announced plans to increase production, which events together contributed to a sharp drop in global oil prices. While OPEC, Russia and other allied producers reached an agreement in April 2020, and most recently in March 2021, to reduce production, oil prices remained low until the first quarter of 2021. While OPEC+ producers ultimately agreed to cut global petroleum output, such cut was not enough to offset the impact of COVID-19 on 2020 demand. As a result of this decrease in demand and increase in supply, oil and natural gas prices decreased, which affected our liquidity. Additionally, with depressed oil and natural gas prices, we incurred a write-down to our oil and gas properties and additional write-downs may be required in future periods if prices decrease from current levels.

The imbalance between the supply of and demand for oil, as well as the uncertainty around the extent and timing of an economic recovery, caused significant market volatility and a substantial adverse effect on commodity prices during the last three quarters of 2020. The Company expects ongoing oil and gas price volatility over the short-term. The full impact of the coronavirus on oil and natural gas prices continues to evolve as of the date of this report. As such, the full magnitude of such events on the Company remains uncertain. Management is actively monitoring the global situation and its impact on the Company's future operations, financial position and liquidity in fiscal year 2020.

As a producer of oil and natural gas, we are recognized as an essential business under various federal, state and local regulations related to the COVID-19 pandemic. We have continued to operate as permitted under these regulations while taking steps to protect the health and safety of our workers. We have implemented protocols to reduce the risk of an outbreak within our field operations, and these protocols have not reduced production or efficiency in a significant manner. A substantial portion of our non-field level employees have transitioned temporarily to remote work-from-home arrangements. With these arrangements in place, we have been able to maintain a consistent level of effectiveness, including maintaining our day-to-day operations, our financial reporting systems and our internal control over financial reporting.

Our oil and natural gas producing properties are located in the Permian Basin. Oil sales represented approximately 96.5% and 98.1% of our total revenue for the twelve months ended December 30, 2020 and 2019, respectively. While natural gas prices also declined as a result of changes in demand, the decline in natural gas prices was far less significant than the decline in oil prices. As of December 31, 2020, we have in place derivative contracts covering 9,000 and 1,750 barrels of oil per day for the calendar years 2021 and 2022, respectively, and covering 6,000 and 5,000 MMBTU of natural gas per day for the calendar years 2021 and 2022, respectively. For 2021, contracts covering 4,500 of the 9,000 barrels of oil are in the form of costless collars of WTI Crude Oil prices. "Costless collars" are the combination of two options, a put option (floor) and a call option (ceiling) with the options structured so that the premium paid for the put option will be offset by the premium received from selling the call option. These collars have floors ranging from $40.00 to $45.00, with an averaged floor of $42.22 and have ceilings ranging between $52.71 and $55.35 per barrel, with an average ceiling of $54.57. The remaining 4,500 barrels of oil in 2021 and all of the 1,750 barrels of oil in 2022 are in the form of swaps of WTI Crude Oil prices. The oil swap prices for 2021 range from $45.00 to $45.96, with an average of $45.42. The oil swap prices for 2022 range from $44.22 to $45.98, with an average of $44.84. All of the contracts for natural gas for both 2021 and 2022 are in the form of swaps of Henry Hub. The swap prices for 2021 and 2022 are $2.991 and $2.7255, respectively. Our 2020 and 2021 derivative hedges resulted in total unrealized fair value loss of approximately $1.2 million during the twelve months ended December 31, 2020 and realized gain on derivates of approximately $22.5 million twelve months ended December 31, 2020. All of our hedges are financial hedges and do not have physical delivery requirements. As such, any decreases in anticipated production, whether as a result of decreased development activity or shut-ins, will not impact our ability to realize the benefits of the hedges.

Our supply chain has experienced some interruptions. In the second quarter of 2020, one of our purchasers cancelled its existing contracts to purchase produced oil from the Company. However, we have since entered into new contracts with an existing purchaser to purchase the oil previously covered by the cancelled contracts. In the second quarter of 2020, the industry overall experienced severe storage capacity constraints with respect to oil and certain natural gas products. Although such restraints have relaxed significantly, we may become subject to such constraints if we are not able to sell our production, or certain components of our production. The lack of a market or available storage for natural gas product or oil could result in us having to shut in production.

In addition, as previously announced, we reduced our drilling and completion capital budget for 2020 by approximately 70% since the beginning of the year. Reductions in the 2020 capital budget may impact production levels in 2021 and forward to the extent fewer wells are brought online.

In May 2020, the Borrowing Base supporting our Credit Facility was subject to its semi-annual redetermination, which led to us entering into a second amendment to our Credit Facility on June 17, 2020. The amendment, among other things, reduces the Company's Borrowing Base under the Credit Facility from $425 million to $375 million. The Company subsequently entered into a third amendment to our Credit Facility on December 23, 2020, subject to its semi-annual redetermination requirement. The amendment, among other things, reduced the Company's Borrowing Base from $375 million to $350 million. During the fourth quarter, the Company paid down approximately $47 million in debt leaving approximately $313 million outstanding on our credit facility as of December 31, 2020.

The COVID-19 pandemic, commodity market volatility and resulting financial market instability are variables beyond our control that can adversely impact our ability to generate sufficient funds from operating activities, our available borrowings under our Credit Facility and our ability to access the capital markets. We believe we are taking appropriate steps in response to the evolving circumstances. However, past performance is not a promise of future events and the Company cannot estimate all aspects of the ongoing impact of the pandemic-related events and the OPEC+ production adjustments on the Company's financial statements.

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future commodity prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our drilling program, production volumes or revenues.

The pandemic induced reduction in oil prices experienced in 2020 caused Ring, as well as other operators, to re-evaluate our original capital budget plans for 2020 that led to changes we believed were in the best interest of the Company and our stockholders. Although oil prices have recovered to pre-pandemic levels, we believe oil and natural gas prices may continue to be volatile. The ability to find and develop sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

For the Years Ended December 31,		**2020**		**2019**		**2018**
Net production:						
Oil (Bbls)		2,801,528		3,536,126		2,047,295
Natural gas (Mcf)		2,494,502		2,476,472		1,112,177
Net sales:						
Oil	$	109,113,557	$	191,891,314	$	116,678,375
Natural gas		3,911,581		3,811,517		3,386,986
Average sales price:						
Oil (per Bbl)	$	38.95	$	54.27	$	56.99
Natural gas (per Mcf)		1.57		1.54		3.05
Production costs and expenses						
Oil and gas production costs (excluding ad valorem taxes)	$	33,843,651	$	45,087,161	$	26,849,214
Ad valorem taxes		3,125,222		3,409,064		952,775
Production taxes		5,228,090		9,130,379		5,631,093
Depreciation, depletion and amortization expense		43,010,660		56,204,269		39,024,886
Ceiling test impairment		277,501,943		—		14,172,309
Realized loss (gain) on derivatives		(22,522,591)		—		11,153,702
Accretion expense		906,616		943,707		606,459
Operating lease expense		1,196,372		925,217		—
General and administrative expense (excluding stock-based compensation)		11,509,888		16,784,081		8,996,752
Stock-based compensation expense		5,364,162		3,082,625		3,870,934

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Oil and natural gas sales. Oil and natural gas sales revenue decreased from 2019 levels by approximately $82.7 million to $113.0 million in 2020. Oil sales decreased approximately $82.8 million while natural gas sales increased approximately $0.1 million. The oil sales decrease was the result of both a decrease in sales volume from 3,536,126 barrels of oil in 2019 to 2,801,528 barrels of oil in 2020 and a decrease in the average realized per barrel oil price from $54.27 in 2019 to $38.95 in 2020. These per barrel amounts are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels. The reduction in oil volume was the result of shutting in production and reducing our capital development program due to oil commodity prices, which led to fewer wells drilled.

The natural gas sales volume increased slightly from 2,476,472 Mcf in 2019 to 2,494,501 Mcf in 2020 and the average realized per Mcf gas price increased from $1.54 in 2019 to $1.57 in 2020. These per Mcf amounts are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. The slight increase is due to higher gas production volumes associated with reservoir de-pressurization at the Northwest Shelf properties.

Oil and natural gas production costs (including ad valorem taxes). Our aggregate oil and natural gas production costs decreased from $48,496,225 in 2019 to $36,968,873 in 2020 and decreased on a BOE basis from $12.28 in 2019 to $11.49 in 2020. These per BOE amounts are calculated by dividing our total production costs by our total volume sold, in BOE. Our production costs decreased due to the extreme focus our operating team began early during the pandemic-induced downturn. We reduced overhead, expense repairs, and converted 29 electrical submersible pumps to rod pumps, which have an overall lower operating cost. In addition, artificial lift optimization has continued to reduce overall well failure rates, resulting in further reductions to operating costs.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales were 4.69% during 2019 and decreased to 4.63% in 2020. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states, and on the possibility that any state may raise its production tax.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense decreased from $56,204,269 in 2019 to $43,010,660 in 2020. The decrease was the result of decreased sales volumes and a reduction in our average depreciation, depletion and amortization rate from $14.23 per BOE during 2019 to $13.37 per BOE during 2020. These per BOE amounts are calculated by dividing our total depreciation, depletion and amortization expense by our total volume sold, in BOE.

Ceiling Test Write-Down. The Company recorded a non-cash write-down of the carrying value of its proved oil and natural gas properties of $277,501,943 for the year ended December 31, 2020 as a result of ceiling test limitations, which is reflected as ceiling test impairments in the accompanying Statements of Operations. The Company did not have any write-downs for the period ended December 31, 2019. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve-month period as of December 31, 2019, adjusted for market differentials, per SEC guidelines. The write-down reduced earnings in the period and is expected to result in a lower depreciation, depletion and amortization rate in future periods. The primary reason for the write-down is a reduction in the oil price used for calculating the reserves from $52.19 to $36.04.

General and administrative expenses (including stock-based compensation). General and administrative expenses decreased from $19,866,706 in 2019 to $16,874,050 in 2020. The decrease was primarily related to acquisition related expenses incurred in 2019.

Interest income. Interest income decreased from $13,511 in 2019 to $8 in 2020. The decrease was the result of lower average cash on hand during 2020.

Interest expense. Interest expense increased from $13,865,556 in 2019 to $17,617,614 in 2020. The increase was the result of having larger amounts outstanding on our credit facility during 2020.

Realized gain on derivatives. During 2020, the Company recorded a realized gain on derivatives of $22,522,591. There was no similar gain or loss recorded during 2019. The gain is the result of the reduction in the oil price during 2020.

Unrealized loss on derivatives. During 2020, the Company recorded an unrealized loss on derivatives of $1,156,523, as compared to a loss of $3,000,078 during 2019. The change was the result of variations between oil prices at the end of those periods versus the derivative contracts we had in place at the end of each year.

Deposit forfeiture income. During 2020, the Company received $5,500,000 in non-refundable deposits from the intended buyer regarding the attempted divestiture of the Company's Delaware assets. With the cancellation of that agreement, the non-refundable deposits were recognized as income on our Statements of Operations. No similar income item occurred during 2019.

Benefit from (Provision for) income taxes. The benefit from (provision for) income taxes changed from a provision of $13,787,654 for 2019 to a benefit of $6,001,176 for 2020. The change was primarily the result of losses due to the ceiling test write-down in 2020 offset by a valuation allowance against the deferred tax asset of $50,553,125.

Net income (loss). The Company had net income of $29,496,551 in 2019 as compared to a net loss of ($253,411,828) in 2020. The change in net income (loss) is primarily the result of the ceiling test write-down in 2020.

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

Oil and natural gas sales. Oil and natural gas sales revenue increased approximately $75.6 million to $195.7 million in 2019. Oil sales increased approximately $75.2 million while natural gas sales increased approximately $0.4 million. The oil sales increase was primarily the result of an increase in sales volume from 2,047,295 barrels of oil in 2018 to 3,536,126 barrels of oil in 2019, partially offset by a decrease in the average realized per barrel oil price from $56.99 in 2018 to $54.27 in 2019. These per barrel amounts are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels.

Natural gas sales volume increased from 1,112,177 Mcf in 2018 to 2,476,472 Mcf in 2019 and the average realized per Mcf gas price decreased from $3.05 in 2018 to $1.54 in 2019. These per Mcf amounts are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. The volume increases are the result of our ongoing development of existing properties.

Oil and natural gas sales volumes increased primarily as a result of the acquisition of the Northwest Shelf assets. Of our 3,536,126 barrels of oil produced in 2019, 1,670,573 barrels came from the Northwest Shelf properties and of our 2,476,472 Mcf of natural gas produced in 2019, 1,221,807 Mcf came from the Northwest Shelf properties.

Oil and natural gas production costs (including ad valorem taxes). Our aggregate oil and natural gas production costs increased from $27,801,989 in 2018 to $48,496,225 in 2019 and decreased on a BOE basis from $12.45 in 2018 to $12.28 in 2019. These per BOE amounts are calculated by dividing our total production costs by our total volume sold, in BOE. The increase in total production costs is primarily a result of the acquisition of the Northwest Shelf assets. The decrease in production costs per BOE is primarily the result increased production volumes from the Northwest Shelf assets.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales were 4.69% during 2018 and decreased to 4.67% in 2019. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states, and on the possibility that any state may raise its production tax.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased by $17,179,383 to $56,204,269 in 2019. The increase was primarily the result of increased production volumes but was partially offset by a decrease in our average depreciation, depletion and amortization rate from $17.54 per BOE during 2018 to $14.23 per BOE during 2019. These per BOE amounts are calculated by dividing our total depreciation, depletion and amortization expense by our total volume sold, in BOE. The reduction in our depletion rate per BOE is primarily the result of added reserves from the acquisition of the Northwest Shelf assets.

Ceiling Test Write-Down. The Company did not have any write-downs for the period ended December 31, 2019. The Company recorded a non-cash write-down of the carrying value of its proved oil and natural gas properties of $14,172,309 for the year ended December 31, 2018 as a result of ceiling test limitations, which is reflected as ceiling test impairments in the accompanying Statements of Operations. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve-month period as of December 31, 2018, adjusted for market differentials, per SEC guidelines. The write-down reduced earnings in the period and is expected to result in a lower depreciation, depletion and amortization rate in future periods.

General and administrative expenses (including stock-based compensation). General and administrative expenses increased from $12,867,686 in 2018 to $19,866,706 in 2019. The increase was primarily related to acquisition related expenses, amortization of deferred financing costs and compensation related expenses.

Interest income. Interest income was $13,511 in 2019 as compared to $97,855 in 2018. The decrease was the result of lower average cash on hand during 2019.

Interest expense. Interest expense was $13,865,556 in 2019 as compared to $427,898 in 2018. The increase was the result of having larger amounts outstanding on our credit facility during 2019.

Realized loss on derivatives. During 2018, the Company recorded a realized loss on derivatives of $11,153,702. There was no similar gain or loss recorded during 2019. The loss was the result of the WTI index price increasing during 2018.

Unrealized gain (loss) on derivatives. During 2019, the Company recorded an unrealized loss on derivatives of $3,000,078, as compared to a gain of $3,968,287 during 2018. The change was the result of variations between oil prices at the end of those periods versus the derivative contracts we had in place at the end of each year.

Provision for income taxes. The provision for income taxes increased from $3,445,721 for 2018 to $13,787,654 for 2019. The increase was the result of higher income before income taxes and also as a result of a $3,965,000 excess tax expense related to share based compensation.

Net income. The Company had net income of $29,496,551 in 2019 as compared to $8,999,760 in 2018. The increase in net income primarily resulted from increased revenues, which was largely the result of the Northwest Shelf acquisition, and not having a ceiling test write down in 2019 partially offset by higher interest and income tax expense.

Liquidity and Capital Resources

Financing of Operations. We have historically funded our operations through cash available from operations and from equity offerings of our stock. Our primary sources of cash in 2020 were from funds generated from the sale of oil and natural gas production and borrowing on our Credit Facility. These cash flows were primarily used to fund our capital expenditures.

Credit Facility. On July 1, 2014, the Company entered into a Credit Agreement with SunTrust Bank, as lender, issuing bank and administrative agent for several banks and other financial institutions and lenders (the "Administrative Agent"), which was amended on April June 14, 2018, May 18, 2016, July 24, 2015, and June 26, 2015. In April 2019, the Company amended and restated its Credit Agreement with the Administrative Agent (as amended and restated, the "Credit Facility"). The amendment and restatement of the Credit Facility, among other things, increases the maximum borrowing amount to $1 billion, extends the maturity date through April 2024 and makes other modifications to the terms of the Credit Facility. This Credit Facility was amended on December 23, 2020 and June 17,2020. The latest amendment adjusted the borrowing base to $350 million and made other modifications to the terms of the Credit Facility. The Credit Facility is secured by a first lien on substantially all of the Company's assets.

The Borrowing Base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The Borrowing Base will be redetermined semi-annually on each May 1 and November 1. The Borrowing Base will also be reduced in certain circumstances such as the sale or disposition of certain oil and gas properties of the Company or its subsidiaries and cancellation of certain hedging positions.

The Credit Facility allows for Eurodollar Loans and Base Rate Loans (as respectively defined in the Credit Facility). The interest rate on each Eurodollar Loan will be the adjusted LIBOR for the applicable interest period plus a margin between 2.5% and 3.5% (depending on the then-current level of Borrowing Base usage). The annual interest rate on each Base Rate Loan is (a) the greatest of (i) the Administrative Agent's prime lending rate, (ii) the Federal Funds Rate (as defined in the Credit Facility) plus 0.5% per annum, (iii) the adjusted LIBOR determined on a daily basis for an interest period of one-month, plus 1.00% per annum and (iv) 0.00% per annum, plus (b) a margin between 1.5% and 2.5% (depending on the then-current level of Borrowing Base usage).

The Credit Facility contains certain covenants, which, among other things, require the maintenance of (i) a total Leverage Ratio (outstanding debt to adjusted earnings before interest, taxes, depreciation and amortization) of not more than 4.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Credit Facility) of 1.0 to 1.0. The amendment to the credit facility in June 2020 allowed for a Leverage Ratio of not greater than 4.75 to 1 as of the last day of the fiscal quarter ending September 30, 2020. The December 2020 amendment permitted a total Leverage Ratio not greater than 4.25 for the period ending March 31, 2021. The Credit Facility also contains other customary affirmative and negative covenants and events of default. As of December 31, 2020, $313,000,000 was outstanding on the Credit Facility. We are in compliance with all covenants contained in the Credit Facility.

Equity Offering. In October 2020, the Company closed on an underwritten public offering of 9,575,800 Common Shares, (ii) 13,428,500 Pre-Funded Warrants and (iii) 23,004,300 Common Warrants at a combined purchase price of $0.70. This includes a partial exercise of the over-allotment. The Common Warrants have a term of five years and an exercise price of $0.80 per share. Gross proceeds totaled $16,089,582.

Concurrently with the underwritten public offering, the Company closed on a registered direct offering of (i) 3,500,000 Common Shares, (ii) 3,300,000 Pre-Funded Warrants and (iii) 6,800,000 Common Warrants at a combined purchase price of $0.70. The Common Warrants have a term of five years and an exercise price of $0.80 per share. Gross proceeds totaled $4,756,700.

Total gross proceeds from the 2020 underwritten public offering and the registered direct offering aggregated $20,846,282. Total net proceeds aggregated $19,383,131.

Cash Flows. Historically, our primary sources of cash have been from operations, equity offerings and borrowings on our Credit Facility. During 2020, 2019 and 2018, we had cash inflow from operations of $72,159,255, $106,616,221 and $70,357,321, respectively. During the three years ended December 31, 2020, we financed $101,204,269 through proceeds from the sale of stock.

During 2020, 2019 and 2018, we had proceeds from drawdowns on our Credit Facility of $26,500,000, $327,000,000, and $39,500,000, respectively. We primarily used this cash to fund our capital expenditures and development aggregating $678,889,233 over the three years ended December 31, 2020. Additionally, during 2020 we used $80,000,000 to reduce the outstanding balance on our Credit Facility. As of December 31, 2020, we had cash on hand of $3,578,634 and negative working capital of $16,141,847, as compared to cash on hand of $10,004,622 and negative working capital of $20,384,013 as of December 31, 2019 and cash on hand of $3,363,726 and negative working capital of $35,066,175 as of December 31, 2018.

Contractual Obligations. The Company maintains a Credit Facility which currently has a $350 million borrowing base. The outstanding balance on that Credit Facility as of December 31, 2020 is $313 million, which will require repayment or refinancing at or prior maturity in April 2024.

The Company leases office space in Midland, Texas. The Midland office is under a five-year lease beginning January 1, 2021 with monthly rent payments of $12,000 through December 2023 and $13,000 per month from January 2024 through December 2025. All other office space as of December 31, 2020 is month to month and will be discontinued during 2021.

The Company leases office equipment in our Midland office. These leases are month-to-month but we anticipate continuing to lease this equipment through the term of the Midland office lease. Payments for this equipment aggregate $711 per month.

The Company also leases field equipment for the operation of our wells. These leases are on a month-to-month basis but we anticipate continuing to lease the equipment until the end of its useful life. The current anticipated useful life of this equipment varies from December 2020 through December 2023. Total payments under these leases are anticipated to be $815,960 through December 2023.

The Company has financing leases for vehicles with varying maturity dates from November 2021 through July 2022. At the end of the term of these leases, the Company will own the vehicles. Future lease payments through July 2022 aggregate $443,705.

Subsequent Events

The Company entered into a Sublease Agreement dated January 15, 2021, covering approximately 15,728 square feet at 1725 Hughes Landing Blvd, Suite 900, The Woodlands, TX 77380. The sublease term will run until July 31, 2026.

The Company entered into a Purchase, Sale and Exchange Agreement dated February 1, 2021, effective January 1, 2021, with Vin Fisher Operating, Inc. covering the sale and exchange of certain oil and gas interests in Andrews County, Texas. After the sale and transfer of wells and leases between the two parties, the Company also received a net value consideration in cash of $2,000,000. The deal greatly reduces the Company's plug and abandonment obligation costs and also allows the Company to acquire new leasehold for the future drilling of additional horizontal wells.

Subsequent to December 31, 2020, the remaining 13,428,500 pre-funded warrants and 184,800 of the Common Warrants issued in the October 2020 offering were exercised. Gross proceeds were $161,269.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do associated costs. Material changes in prices impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and the value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. We anticipate business costs will vary in accordance with commodity prices for oil and natural gas, and the associated increase or decrease in demand for services related to production and exploration.

Off-Balance Sheet Financing Arrangements

As of December 31, 2020, we had no off-balance sheet financing arrangements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our financial statements. The preparation of these statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. Our significant accounting policies are detailed in Note 1 to our financial statements included in this Annual Report. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Revenue Recognition. In January 2018, the Company adopted Accounting Standards Update ("ASU") 2014-09 *Revenues from Contracts with Customers (Topic 606)* ("ASU 2014-09"). The timing of recognizing revenue from the sale of produced crude oil and natural gas was not changed as a result of adopting ASU 2014-09. The Company predominantly derives its revenue from the sale of produced crude oil and natural gas. The contractual performance obligation is satisfied when the product is delivered to the customer. Revenue is recorded in the month the product is delivered to the purchaser. The Company receives payment from one to three months after delivery. The transaction price includes variable consideration as product pricing is based on published market prices and reduced for contract specified differentials. The new guidance regarding ASU 2014-09 does not require that the transaction price be fixed or stated in the contract. Estimating the variable consideration does not require significant judgment and Ring engages third party sources to validate the estimates. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration the Company expects to receive in exchange for those products. See Note 2 of our financial statements for additional information.

Full Cost Method of Accounting. We account for our oil and natural gas operations using the full cost method of accounting. Under this method, all costs (internal or external) associated with property acquisition, exploration and development of oil and gas reserves are capitalized. Costs capitalized include acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and cost of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. All of our properties are located within the continental United States.

Write-down of Oil and Natural Gas Properties. Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly utilizing the average of prices in effect on the first day of the month for the preceding twelve-month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

During 2018 and 2020, the Company recorded non-cash write-downs of the carrying value of the Company's proved oil and natural gas properties as a result of ceiling test limitations of approximately $14.2 million and $277.5 million, respectively, which is reflected with ceiling test and other impairments in the accompanying Statements of Operations. The Company did not have any write-downs related to the full cost ceiling limitation in 2019.

Our estimates of reserves and future cash flow as of December 31, 2020 and 2019 were prepared using an average price equal to the unweighted arithmetic average of the first day of the month price for each month within the 12-month periods ended December 31, 2020 and 2019, respectively, in accordance with SEC guidelines. As of December 31, 2020, our reserves are based on an SEC average price of $36.04 per Bbl of WTI oil posted and $1.99 per MMBtu Henry Hub natural gas. As of December 31, 2019, our reserves are based on an SEC average price of $52.19 per Bbl of WTI oil posted and $2.58 per MMBtu Henry Hub natural gas. Prices are adjusted by local field and lease level differentials and are held constant for life of reserves in accordance with SEC guidelines.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this Annual Report are prepared in accordance with guidelines established by the SEC and FASB. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the persons preparing the estimates.

Our proved reserve information included in this Annual Report was prepared and determined by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional properties are acquired. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made.

All capitalized costs of oil and natural gas properties, including estimated future costs to develop proved reserves and estimated future costs of site restoration, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent engineers. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined.

Income Taxes. Deferred income taxes are provided for the difference between the tax basis of assets and liabilities and the carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is settled. Since our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to the actual values in the period we file our tax returns. For the year ended December 31, 2020, we recorded a valuation allowance against our deferred tax asset of $50,553,125. We were in a deferred tax asset position as a result of the ceiling test write downs recorded during 2020. No valuation allowance was recorded for the years ended December 31, 2019 or 2018.

In January 2017, the Company adopted ASU 2016-09, *Compensation – Stock Compensation (Topic 718.)* The Company used the modified retrospective method to account for unrecognized excess tax benefits from prior periods and uses the prospective method to account for current period and future excess tax benefit. For the years ended December 31, 2020, 2019 and 2018, we recorded a decrease of $2,026,006, an increase of $3,855,389 and an increase of $907,884, respectively, to our income tax provision.

Item 7A: Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Market risk refers to the risk of loss from adverse changes in oil and natural gas prices. Realized pricing is primarily driven by the prevailing domestic price for crude oil and spot prices applicable to the region in which we produce natural gas. Historically, prices received for oil and natural gas production have been volatile and unpredictable. We expect pricing volatility to continue.

The prices we receive depend on many factors outside of our control. Oil prices we received during 2020 ranged from a low of $13.23 per barrel to a high of $57.36 per barrel. Natural gas prices we received during 2020 ranged from a low of negative $0.93 per Mcf to a high of $3.38 per Mcf. A significant decline in the prices of oil or natural gas could have a material adverse effect on our financial condition and results of operations. In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we may enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. As of December 31, 2020, the Company has in place derivative contracts covering 9,000 and 1,750 barrels of oil per day for the calendar years 2021 and 2022, respectively, and covering 6,000 and 5,000 MMBTU of natural gas per day for the calendar years 2021 and 2022, respectively. For 2021, contracts covering 4,500 of the 9,000 barrels of oil are in the form of costless collars of WTI Crude Oil prices. "Costless collars" are the combination of two options, a put option (floor) and a call option (ceiling) with the options structured so that the premium paid for the put option will be offset by the premium received from selling the call option. These collars have floors ranging from $40.00 to $45.00, with an averaged floor of $42.22 and have ceilings ranging between $52.71 and $55.35 per barrel, with an average ceiling of $54.57. The remaining 4,500 barrels of oil in 2021 and all of the 1,750 barrels of oil in 2022 are in the form of swaps of WTI Crude Oil prices. The oil swap prices for 2021 range from $45.00 to $45.96, with an average of $45.42. The oil swap prices for 2022 range from $44.22 to $45.98, with an average of $44.84. All of the contracts for natural gas for both 2021 and 2022 are in the form of swaps of Henry Hub. The swap prices for 2021 and 2022 are $2.991 and $2.7255, respectively. See Note 8 to our Financial Statements for further information.

Customer Credit Risk

Our principal exposure to credit risk is through receivables from the sale of our oil and natural gas production (approximately $15.0 million as of December 31, 2020). We are subject to credit risk due to the concentration of our oil and natural gas receivables with our most significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the fiscal year 2020, sales to three customers, Phillips 66, Oxy and NGL Crude represented 68%, 10% and 8%, respectively, of oil and natural gas revenues. As of December 31, 2020, Phillips 66 represented 80% of our accounts receivable, Oxy represented 0% of our accounts receivable and NGL Crude represented 5% of our accounts receivable. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility, which bears variable interest based upon a prime rate and is therefore susceptible to interest rate fluctuations. Changes in interest rates affect the interest earned on the Company’s cash and cash equivalents and the interest rate paid on borrowings under the Credit Facility.

As of December 31, 2020, we had $313 million outstanding on our Credit Facility with a weighted average interest rate of 4.5%. A 1% change in the interest rate on our Credit Facility would result in an estimated $3,130,000 change in our annual interest expense. See note 10 in the Footnotes to the Financial Statements for more information on the Company’s interest rates on our Credit Facility.

Currently, the Company does not use interest rate derivative instruments to manage exposure to interest rate changes.

Please also see Item 1A “Risk Factors” above for a discussion of other risks and uncertainties we face in our business.

Item 8: Financial Statements and Supplementary Data

The financial statements and supplementary data required by this item are included beginning at page F-1 of this Annual Report.

Item 9: Changes in and Disagreements with Accountants and Accounting and Financial Disclosure

None.

Item 9A: Controls and Procedures

Evaluation of disclosure controls and procedures.

Our management, with the participation of our chief executive officer and chief financial officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Exchange Act. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs. Based on their evaluation and as of the date of that evaluation, these officers concluded that the Company's disclosure controls and procedures were effective.

Changes in internal control over financial reporting.

We regularly review our system of internal control over financial reporting and make changes to our processes and systems to improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes. During the fiscal year ended December 31, 2020, the Company incorporated procedures from our annual review process into our quarterly review process in order to remediate a material weakness identified during 2019. These changes included preparing additional schedules and incorporating some additional third-party review. We believe these additional steps adequately remediate the material weakness.

Except as described above, there were no changes in our internal control over financial reporting that occurred during the fiscal year ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting and Report of Independent Accounting Firm

Our management is responsible for establishing and maintaining adequate internal controls over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

In making our assessment of internal control over financial reporting, our management used the criteria issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013)*. Based on our assessment, we believe that, as of December 31, 2020, our internal control over financial reporting is effective based on those criteria.

The registered public accounting firm, Eide Bailly LLP, has audited the financial statements included in this annual report and has issued an attestation report on our internal control over financial reporting. The report is set forth under the caption "Report of Independent Registered Public Accounting Firm" in Item 8 of this annual report.

Item 9B: Other Information

None.

PART III

Item 10: Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated by reference herein from the 2021 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2020. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

Item 11: Executive Compensation

The information required by this item is incorporated by reference herein from the 2021 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2020. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

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

The information required by this item is incorporated by reference herein from the 2021 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2020. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

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

The information required by this item is incorporated by reference herein from the 2021 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2020. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

Item 14: Principal Accounting Fees and Services

The information required by this item is incorporated by reference herein from the 2021 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2020. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

PART IV

Item 15: Exhibits, Financial Statement Schedules

(a) Financial Statements

The following financial statements are filed with this Annual Report:

Report of Independent Registered Public Accounting Firm

Balance Sheets as of December 31, 2020 and 2019

Statements of Operations for the years ended December 31, 2020, 2019 and 2018

Statements of Stockholders' Equity for the years ended December 31, 2020, 2019 and 2018

Statements of Cash Flows for the years ended December 31, 2020, 2019 and 2018

Notes to Financial Statements

Supplemental Information on Oil and Gas Producing Activities

Exhibit Number	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Here-with
2.1	Stock for Stock Exchange Agreement dated May 3, 2012	8-K	000-53920	2.1	7/5/12	
2.2	Merger Agreement dated November 7, 2012	8-K	000-53920	2.1	11/26/12	
2.3	Purchase and Sale Agreement, dated February 25, 2019 by and among Ring Energy, Inc. and Wishbone Energy Partners, LLC, Wishbone Texas operating Company LLC and WB WaterWorks, LLC	8-K	001-36057	2.1	2/28/19	
3.1	Articles of Incorporation (as amended)	10-K	000-53920	3.1	4/1/13	
3.2	Current Bylaws	8-K	000-53920	3.2	1/24/13	
4.1	Registration Rights Agreement, dated April 9, 2019 by and between Ring Energy, Inc. and Wishbone Energy Partners, LLC	10-Q	001-36057	4.1	4/12/19	
4.2	Description of Ring Energy, Inc. equity securities registered under Section 12(b) of the Securities Exchange Act of 1934, as amended	10-K	001-36057	4.2	3/16/20	
4.3	Securities Purchase Agreement, dated October 27, 2020	8-K	001-36057	4.1	10/29/20	
10.1	Letter Agreement with Patriot Royalty & Land, LLC entered into on March 1, 2012	10-K	000-53920	10.1	3/20/12	
10.2	Executive Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Stephen D. Brooks	8-K	001-36957	10.1	12/4/20	
10.3	Executive Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Paul D. McKinney	8-K	001-36957	10.1	10/6/20	
10.4	Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Alexander Dyes	8-K	001-36057	10.1	12/22/20	
10.5	Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Marinos C. Baghdati	8-K	001-36057	10.2	12/22/2-	
10.6*	Ring Energy Inc. Long Term Incentive Plan, as Amended	8-K	000-53920	99.3	1/24/13	
10.7*	Form of Option Grant for Long-Term Incentive Plan	10-Q	000-53920	10.2	8/14/12	
10.8	Executive Committee Charter	10-K	000-53920	3.1	4/1/13	
10.9	Audit Committee Charter	10-K	000-53920	3.1	4/1/13	
10.10	Compensation Committee Charter	10-K	000-53920	3.1	4/1/13	
10.11	Nominating and Corporate Governance Committee Charter	10-K	000-53920	3.1	4/1/13	
10.12	Credit Agreement dated July 1, 2014 with SunTrust Bank[1]	8-K	001-36057	10.1	7/3/14	
10.13	First Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	6/29/15	
10.14	Second Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	7/29/15	
10.15	Third Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	5/20/16	
10.16	Fourth Amendment to Credit Agreement with SunTrust Bank					X

10.17	Fifth Amendment to Credit Agreement with SunTrust	8-K	001-36057	10.1	6/19/18	
10.18	Amended and Restated Credit Agreement with SunTrust Bank	10-Q	001-36057	10.2	5/8/19	
10.19	First Amendment to Amended and Restated Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	12/9/19	
10.20	Second Amendment to Amended and Restated Credit Agreement, dated June 17, 2020, by and among Ring Energy, Inc., the lenders party thereto, and Truist Bank, as administrative agent for the lenders and as issuing bank	8-K	001-36057	10.1	6/19/20	
10.21	Third Amendment to Amended and Restated Credit Agreement with Truist Bank	8-K	001-36057	10.1	12/29/20	
10.22	Development Agreement with Torchlight Energy Resources, Inc.	8-K	001-36057	10.1	10/18/13	
10.23	Purchase and Sale Agreement, dated February 4, 2014, between Ring Energy, Inc. and Raw Oil & Gas, Inc., JDH Raw LC, and Smith Energy Company	8-K	001-36057	10.1	2/7/14	
10.24	Purchase and Sale Agreement effective May 1, 2015, with Finley Production Co., LP, BDT Oil & Gas, LP, Metcalfe Oil, LP, Grasslands Energy, LP, Buffalo Oil & Gas, LP and Finley Resources, Inc.	8-K	001-36057	2.1	5/22/15	
10.25	Commitment Letter dated February 24, 2019, between Ring Energy, Inc., SunTrust Bank and SunTrust Robinson Humphrey, Inc.	8-K	001-36057	2.1	2/28/19	
14.1	Code of Ethics	8-K	000-53920	14.1	1/24/13	
16.1	Letter dated April 19, 2012, from Haynie & Company	8-K	000-53920	16.1	4/19/12	
23.1	Consent of Cawley, Gillespie & Associated, Inc.					X
23.2	Consent of Eide Bailly LLP					X
23.3	Consent of Moss Adams LLP	8-K/A	001-36057	23.1	6/19/19	
31.1	Rule 13a-14(a) Certification by Chief Executive Officer					X
31.2	Rule 13a-14(a) Certification by Chief Financial Officer					X
32.1	Section 1350 Certification of Chief Executive Officer					X
32.2	Section 1350 Certification Chief Financial Officer					X
99.1	Reserve Report of Cawley, Gillespie & Associates, Inc.					X
101.INS	Inline XBRL Instance Document					X
101.SCH	Inline XBRL Taxonomy Extension Schema Document					X
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document					X
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).					

* Management contract

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on behalf by the undersigned, thereunto duly authorized.

Ring Energy, Inc.

By: */s/ Paul D. McKinney*
Mr. Paul D. McKinney
Chief Executive Officer

Date: March 16, 2021

By: */s/ William R. Broaddrick*
Mr. William R. Broaddrick
Chief Financial Officer

Date: March 16, 2021

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

/s/ Paul D. McKinney
Mr. Paul D. McKinney
Director

Date: March 16, 2021

/s/ Anthony B. Petrelli
Mr. Anthony B. Petrelli
Director

Date: March 16, 2021

/s/ Regina Roesener
Mrs. Regina Roesener
Director

Date: March 16, 2021

/s/ Clayton E. Woodrum
Mr. Clayton E. Woodrum
Director

Date: March 16, 2021

/s/ Richard Harris
Mr. Richard Harris
Director

Date: March 16, 2021

/s/ John Crum
Mr. John Crum
Director

Date: March 16, 2021

/s/ Thomas Mitchell
Mr. Thomas Mitchell
Director

Date: March 16, 2021

RING ENERGY, INC.

INDEX TO FINANCIAL STATEMENTS

CPAs & BUSINESS ADVISORS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Ring Energy, Inc.
The Woodlands, Texas

Opinions on the Financial Statements and Internal Control Over Financial Reporting
We have audited the accompanying balance sheets of Ring Energy, Inc. (Ring Energy) as of December 31, 2020 and 2019, and the related statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Ring Energy as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We also have audited Ring Energy's internal control over financial reporting as of December 31, 2020, based on criteria established in 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, Ring Energy maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in 2013 Internal Control—Integrated Framework issued by COSO.

Basis for Opinion
Ring Energy's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express an opinion on the entity's financial statements and an opinion on the entity's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to Ring Energy 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 financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee that (1) relate to accounts or disclosures that are material to the financial statements and (2) involve our especially challenging, subjective, or complex judgement. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Depletion expense and ceiling test calculation of oil and natural gas properties impacted by the estimation of proved oil and natural gas reserves

As described further in Note 1 to the financial statements, the Company uses the full cost method of accounting for oil and natural gas properties. This accounting method requires management to make estimates of proved oil and natural gas reserves and related future cash flows to compute and record depreciation, depletion and amortization expense, as well as to assess potential impairment of oil and natural gas properties (the full cost ceiling test). To estimate the volume of proved oil and natural gas reserves quantities, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved oil and natural gas reserves is also impacted by management's judgements and estimates regarding the financial performance of wells associated with those proved oil and natural gas reserves to determine if wells are expected to be economical under the appropriate pricing assumptions that are required in the estimation of depreciation, depletion and amortization expense and potential ceiling test impairment assessments. We identified the estimation of proved oil and natural gas reserves as it relates to the recognition of depreciation, depletion and amortization expense and the assessment of potential impairment as a critical audit matter.

The principal consideration for our determination that the estimation of proved oil and natural gas reserves is a critical audit matter is that there is significant judgement by management and use of specialist in developing the estimates of proved oil and natural gas reserves and a relatively minor change in certain inputs and assumptions that are necessary to estimate the volume and future cash flows of the Company's proved oil and natural gas reserves could have a significant impact on the measurement of depreciation, depletion and amortization expense and/or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgement.

Our audit procedures related to the estimation of proved oil and natural gas reserves included the following, among others.

- We tested the design and operating effectiveness of internal controls relating to management's estimation of proved oil and natural gas reserves for the purpose of estimating depreciation, depletion and amortization expense and assessing for ceiling test impairment.
- We evaluated the independence, objectivity, and professional qualifications of the Company's independent petroleum engineer specialist and read the report prepared by the Company's independent petroleum engineer specialist.

- We evaluated the sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions that are derived from the Company's accounting records, such as historical pricing differentials, operating costs, estimated capital costs, and ownership interests. We tested management's process for determining the assumptions, including the underlying support, on a sample basis where applicable. Specifically, our audit procedures involved testing management's assumptions as follows:
  - Tested the working and net revenue interest used in the reserve report
  - Tested the model used to determine the future capital expenditures by comparing estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells, where applicable;
  - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year;
  - Tested the model used to estimate the operating costs at year end and compared to historical operating costs;
  - Evaluated the Company's evidence supporting the proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties.

EideBailly

CPAs & BUSINESS ADVISORS

Valuation Allowance of Deferred Tax Assets

As described in Note 1 to the financial statements, the Company records a valuation allowance to reduce total net deferred tax assets when a judgement is made that is considered more likely than not that a tax benefit will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences will become deductible. We identified the realizability of deferred tax assets as a critical audit matter.

The principal considerations for our determination that the realizability of deferred tax assets is a critical audit matter are that (a) the forecast of future taxable income is subject to a high level of estimation and (b) the determination of any limitations on the utilization of net operating loss carryforwards involve complex calculations and judgement. There is inherent uncertainty and subjectivity related to management's judgements and assumptions regarding the Company's future taxable income, which are complex in nature and require significant auditor judgment.

Our audit procedures related to the valuation of deferred tax assets included the following, among others.

- We tested the effectiveness of controls over management's estimate of the realization of the deferred tax assets and management's tax planning strategies and the determination of whether it is more likely than not that the deferred tax assets will be realized prior to expiration.
- We tested the reasonableness of management's corporate model used to estimate future taxable income by comparing the estimates to the following:
    - Historical taxable income.
    - Evidence obtained in other areas of the audit.
    - Management's history of carrying out its stated plans and its ability to carry out its plans.

We have served as Ring Energy's auditor since 2013.

Eide Bailly LLP

Denver, Colorado
March 16, 2021

RING ENERGY, INC.
BALANCE SHEET
(Unaudited)

As of December 31,	2020	2019
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,578,634	$ 10,004,622
Accounts receivable	14,997,979	22,909,195
Joint interest billing receivable	1,327,262	1,812,469
Derivative receivable	499,906	—
Prepaid expenses and retainers	396,109	3,982,255
Total Current Assets	20,799,890	38,708,541
Properties and Equipment		
Oil and natural gas properties subject to amortization	836,514,815	1,083,966,135
Financing lease asset subject to depreciation	858,513	858,513
Fixed assets subject to depreciation	1,520,890	1,465,551
Total Properties and Equipment	838,894,218	1,086,290,199
Accumulated depreciation, depletion and amortization	(200,111,658)	(157,074,044)
Net Properties and Equipment	638,782,560	929,216,155
Operating lease asset	1,494,399	1,867,044
Deferred Financing Costs	2,379,348	3,214,408
Total Assets	$ 663,456,197	$ 973,006,148
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 32,500,081	$ 54,635,602
Financing lease liability	295,311	280,970
Operating lease liability	859,017	1,175,904
Derivative liabilities	3,287,328	3,000,078
Total Current Liabilities	36,941,737	59,092,554
Deferred income taxes	—	6,001,176
Revolving line of credit	313,000,000	366,500,000
Financing lease liability, less current portion	126,857	424,126
Operating lease liability, less current portion	635,382	691,140
Derivative liabilities	869,273	—
Asset retirement obligations	17,117,135	16,787,219
Total Liabilities	368,690,384	449,496,215
Stockholders' Equity		
Preferred stock - $0.001 par value; 50,000,000 shares authorized; no shares issued or outstanding	—	—
Common stock - $0.001 par value; 150,000,000 shares authorized; 85,568,287 shares and 67,993,797 shares issued and outstanding, respectively	85,568	67,994
Additional paid-in capital	550,951,415	526,301,281
Accumulated deficit	(256,271,170)	(2,859,342)
Total Stockholders' Equity	294,765,813	523,509,933
Total Liabilities and Stockholders' Equity	$ 663,456,197	$ 973,006,148

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

RING ENERGY, INC.
CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

For the years ended December 31,	2020	2019	2018
Oil and Natural Gas Revenues	$ 113,025,138	$ 195,702,831	$ 120,065,361
Costs and Operating Expenses			
Oil and natural gas production costs	36,968,873	48,496,225	27,801,989
Oil and natural gas production taxes	5,228,090	9,130,379	5,631,093
Depreciation, depletion and amortization	43,010,660	56,204,269	39,024,886
Ceiling test impairment	277,501,943	—	14,172,309
Asset retirement obligation accretion	906,616	943,707	606,459
Operating lease expense	1,196,372	925,217	—
General and administrative expense	16,874,050	19,866,706	12,867,686
Total Costs and Operating Expenses	381,686,604	135,566,503	100,104,422
Income (Loss) from Operations	(268,661,466)	60,136,328	19,960,939
Other Income (Expense)			
Interest income	8	13,511	97,855
Interest (expense)	(17,617,614)	(13,865,556)	(427,898)
Realized gain (loss) on derivatives	22,522,591	—	(11,153,701)
Unrealized gain (loss) on change in fair value of derivatives	(1,156,523)	(3,000,078)	3,968,286
Deposit forfeiture income	5,500,000	—	—
Net Other Income (Expense)	9,248,462	(16,852,123)	(7,515,458)
Income (Loss) Before Provision for Income Taxes	(259,413,004)	43,284,205	12,445,481
Benefit from (Provision for) Income Taxes	6,001,176	(13,787,654)	(3,445,721)
Net Income (Loss)	$ (253,411,828)	$ 29,496,551	$ 8,999,760
Basic Earnings (Loss) per share	$ 3.48	$ 0.44	$ 0.15
Diluted Earnings (Loss) per share	$ 3.48	$ 0.44	$ 0.15

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

RING ENERGY, INC.
STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in	Retained Earnings (Accumulated	Total Stockholders'
	Shares	Amount	Capital	Deficit)	Equity
Balance, December 31, 2017	54,224,029	$ 54,224	$ 397,904,769	$ (41,355,653)	$ 356,603,340
Share-based compensation	—	—	3,870,934	—	3,870,934
Options exercised (cashless exercise)	103,113	103	(103)	—	—
Options exercised	50,000	50	99,950	—	100,000
Restricted stock vested	64,620	65	(65)	—	—
Common stock issued for cash, net	6,164,000	6,164	81,814,974	—	81,821,138
Common stock issued for property acquisition	2,623,948	2,624	11,201,634	—	11,204,258
Net income	—	—	—	8,999,760	8,999,760
Balance, December 31, 2018	63,229,710	$ 63,230	$ 494,892,093	$ (32,355,893)	$ 462,599,430
Common stock issued as partial consideration in acquisition	4,576,951	4,577	28,326,750	—	28,331,327
Restricted stock vested	187,136	187	(187)	—	—
Share-based compensation	—	—	3,082,625	—	3,082,625
Net income	—	—	—	29,496,551	29,496,551
Balance, December 31, 2019	67,993,797	$ 67,994	$ 526,301,281	$ (2,859,342)	$ 523,509,933
Return of common stock issued as consideration in asset acquisition	(16,702)	(17)	(103,368)	—	(103,385)
Common stock and warrants issued for cash, net	13,075,800	13,076	19,366,756	—	19,379,832
Exercise of pre-funded warrants issued in offering	3,300,000	3,300	—	—	3,300
Common stock issued for services	35,000	35	23,765	—	23,800
Restricted stock vested	1,180,392	1,180	(1,180)	—	—
Share-based compensation	—	—	5,364,162	—	5,364,162
Net (loss)	—	—	—	(253,411,828)	(253,411,828)
Balance, December 31, 2020	85,568,287	$ 85,568	$ 550,951,415	$ (256,271,170)	$ 294,765,813

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

RING ENERGY, INC.
STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2020	2019	2018
Cash Flows From Operating Activities			
Net income (loss)	$ (253,411,828)	$ 29,496,551	$ 8,999,760
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	43,010,660	56,204,269	39,024,886
Ceiling test impairment	277,501,943	—	14,172,309
Accretion expense	906,616	943,707	606,459
Amortization of deferred financing costs	1,190,109	991,310	—
Stock-based compensation	5,364,162	3,082,625	3,870,934
Shares issued for services	23,800	—	—
Deferred income tax expense (benefit)	(3,975,170)	9,500,517	2,537,837
Excess tax expense (benefit) related to stock-based compensation	(2,026,006)	3,855,389	907,884
Adjustment to deferred tax asset for change in effective tax rate	—	431,748	—
Change in fair value of derivative instruments	1,156,523	3,000,078	(3,968,286)
Changes in assets and liabilities:			
Accounts receivable	7,896,517	(10,035,648)	666,283
Prepaid expenses and retainers	3,586,146	(1,878,667)	(318,190)
Accounts payable	(8,380,594)	12,320,308	4,435,269
Settlement of asset retirement obligation	(683,623)	(1,295,966)	(577,824)
Net Cash Provided by Operating Activities	72,159,255	106,616,221	70,357,321
Cash Flows From Investing Activities			
Payments for the Wishbone Acquisition	—	(276,061,594)	—
Payments to purchase oil and natural gas properties	(1,317,313)	(3,400,411)	(4,656,484)
Proceeds from divestiture of oil and natural gas properties	—	8,547,074	—
Payments to develop oil and natural gas properties	(42,457,745)	(152,125,320)	(198,870,366)
Proceeds from disposal of fixed assets subject to depreciation	—	—	105,536
Purchase of fixed assets subject to depreciation	(55,339)	—	—
Net Cash Used in Investing Activities	(43,830,397)	(423,040,251)	(203,421,314)
Cash Flows From Financing Activities			
Proceeds from revolving line of credit	26,500,000	327,000,000	39,500,000
Payments on revolving line of credit	(80,000,000)	—	—
Proceeds from issuance of common stock and warrants	19,383,131	—	81,821,138
Proceeds from option exercise	—	—	100,000
Payment of deferred financing costs	(355,049)	(3,781,657)	—
Reduction of financing lease liabilities	(282,928)	(153,417)	—
Net Cash Provided by (Used in) Financing Activities	(34,754,846)	323,064,926	121,421,138
Net Increase (Decrease) in Cash	(6,425,988)	6,640,896	(11,642,855)
Cash at Beginning of Period	10,004,622	3,363,726	15,006,581
Cash at End of Period	$ 3,578,634	$ 10,004,622	$ 3,363,726
Supplemental Cash Flow Information			
Cash paid for interest	$ 16,911,344	$ 10,364,313	$ 323,916
Noncash Investing and Financing Activities			
Asset retirement obligation incurred during development	$ 99,436	$ 631,727	$ 1,311,956
Asset retirement obligation acquired	—	39,701	2,571,549
Asset retirement obligation revision of estimate	34,441	—	87,960
Operating lease assets obtained in exchange for new operating lease liability	823,727	2,319,185	—
Financing lease assets obtained in exchange for new financing lease liability	—	858,513	—
Prepaid asset settled in divestiture of oil and natural gas properties	—	1,019,876	—
Oil and gas assets and properties acquired through stock issuance	—	—	11,204,258
Stock issued in property acquisition returned in final settlement	103,385	—	—
Capitalized expenditures attributable to drilling projects financed through current liabilities	1,415,073	15,170,000	26,000,000
Supplemental Schedule of Investing Activities Wishbone Acquisition			
Assumption of joint interest billing receivable	—	1,464,394	—
Assumption of prepaid assets	—	2,864,554	—
Assumption of accounts and revenue payables	—	(1,234,861)	—
Asset retirement obligation incurred through acquisition	—	(3,705,941)	—
Common stock issued as partial consideration in acquisition	—	(28,331,327)	—
Oil and gas properties subject to amortization	—	305,004,775	—
Cash paid	—	276,061,594	—

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

RING ENERGY, INC.
NOTES TO FINANCIAL STATEMENTS

NOTE 1 – ORGANIZATION, BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations **–** Ring Energy, Inc. is a Nevada corporation. Ring Energy, Inc. is referred to herein as the “Company.” The Company owns interests in oil and natural gas properties located in Texas and New Mexico and is engaged primarily in the acquisition, exploration and development of oil and natural gas properties and the production and sale of oil and natural gas.

Use of Estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (“US GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analysis could have a significant impact on the future results of operations.

Fair Value Measurements - Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Financial Accounting Standards Board ("FASB") has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

Fair Values of Financial Instruments – The carrying amounts reported for the revolving line of credit approximates fair value because the underlying instruments are at interest rates which approximate current market rates. The carrying amounts of receivables and accounts payable and other current assets and liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities.

Fair Value of Non-financial Assets and Liabilities – The Company also applies fair value accounting guidance to initially, or as events dictate, measure non-financial assets and liabilities such as those obtained through business acquisitions, property and equipment and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances. Under the discounted cash flow method, estimated future cash flows are based on management’s expectations for the future and include estimates of future oil and natural gas production or other applicable sales estimates, operational costs and a risk-adjusted discount rate. The Company may use the present value of estimated future cash inflows and/or outflows or third-party offers or prices of comparable assets with consideration of current market conditions to value its non-financial assets and liabilities when circumstances dictate determining fair value is necessary. Given the significance of the unobservable nature of a number of the inputs, these are considered Level 3 on the fair value hierarchy.

Concentration of Credit Risk and Accounts Receivable – Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and accounts receivable. The Company has cash in excess of federally insured limits of $3,328,634 and $9,754,622 as of December 31, 2020 and 2019, respectively. The Company places its cash with a high credit quality financial institution.

Substantially all of the Company’s accounts receivable is from purchasers of oil and natural gas. Oil and natural gas sales are generally unsecured. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectable. The Company also has a joint interest billing receivable. Joint interest billing receivables are collateralized by the pro rata revenue attributable to the joint interest holders and further by the interest itself. Accordingly, no allowance for doubtful accounts has been provided as of December 31, 2020 and 2019.

Cash and Cash Equivalents – The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Oil and Natural Gas Properties – The Company uses the full cost method of accounting for oil and natural gas properties. Under this method, all costs (direct and indirect) associated with acquisition, exploration, and development of oil and natural gas properties are capitalized. Costs capitalized include acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. Capitalized costs are categorized either as being subject to amortization or not subject to amortization.

The Company records a liability in the period in which an asset retirement obligation ("ARO") is incurred, in an amount equal to the discounted estimated fair value of the obligation that is capitalized. Thereafter this liability is accreted up to the final retirement cost. An ARO is a future expenditure related to the disposal or other retirement of certain assets. The Company's ARO relates to future plugging and abandonment expenses of its oil and natural gas properties and related facilities disposal.

All capitalized costs of oil and natural gas properties, including the estimated future costs to develop proved reserves and estimated future costs to plug and abandon wells and costs of site restoration, less the estimated salvage value of equipment associated with the oil and natural gas properties, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent petroleum engineers. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is offset to the capitalized costs to be amortized. The following table shows total depletion and the depletion per barrel-of-oil-equivalent rate, for the years ended December 31, 2020, 2019 and 2018.

	For the Years Ended December 31,		
	2020	2019	2018
Depletion	$ 42,634,294	$ 55,870,246	$ 38,810,864
Depletion rate, per barrel-of-oil-equivalent (BOE)	$ 13.25	$ 14.15	$ 17.38

In addition, capitalized costs less accumulated depreciation, depletion and amortization and related deferred income taxes shall not exceed an amount (the full cost ceiling) equal to the sum of:

1) the present value of estimated future net revenues discounted ten percent computed in compliance with SEC guidelines;

2) plus the cost of properties not being amortized;

3) plus the lower of cost or estimated fair value of unproven properties included in the costs being amortized;

4) less income tax effects related to differences between the book and tax basis of the properties.

For the years ended December 31, 2020 and 2018, the Company recognized impairments on oil and natural gas properties as a result of the ceiling test in the amount of $277,501,943 and $14,172,309, respectively. No impairment was recorded for the year ended December 31, 2019.

Land, Buildings, Equipment and Leasehold Improvements – Land, buildings, equipment and leasehold improvements are carried at historical cost, adjusted for impairment loss and accumulated depreciation. Historical costs include all direct costs associated with the acquisition of land, buildings, equipment and leasehold improvements and placing them in service.

Depreciation of buildings equipment , software and leasehold improvements is calculated using the straight-line method based upon the following estimated useful lives:

Leasehold improvements	3-10 years
Office equipment and software	3-7 years
Equipment	5-10 years

Depreciation expense was $376,366, $334,023 and $214,022 for the years ended December 31, 2020, 2019 and 2018, respectively.

Revenue Recognition – In January 2018, the Company adopted Accounting Standards Update ("ASU") 2014-09 *Revenues from Contracts with Customers (Topic 606)* ("ASU 2014-09"). The timing of recognizing revenue from the sale of produced crude oil and natural gas was not changed as a result of adopting ASU 2014-09. The Company predominantly derives its revenue from the sale of produced crude oil and natural gas. The contractual performance obligation is satisfied when the product is delivered to the customer. Revenue is recorded in the month the product is delivered to the purchaser. The Company receives payment from one to three months after delivery. The transaction price includes variable consideration as product pricing is based on published market prices and reduced for contract specified differentials. The new guidance regarding ASU 2014-09 does not require that the transaction price be fixed or stated in the contract. Estimating the variable consideration does not require significant judgment and Ring engages third party sources to validate the estimates. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration the Company expects to receive in exchange for those products. See Note 2 for additional information.

Income Taxes – Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes. Deferred taxes are provided on differences between the tax basis of assets and liabilities and their reported amounts in the financial statements, and tax carry forwards. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the provision for income taxes.

In January 2017, the Company adopted ASU 2016-09, *Compensation – Stock Compensation (Topic 718.)* The Company used the modified retrospective method to account for unrecognized excess tax benefits from prior periods and uses the prospective method to account for current period and future excess tax benefit. For the years ended December 31, 2020, 2019 and 2018, we recorded a benefit of $2,026,006, a provision of $3,855,389 and a provision of $907,884, respectively, to our income tax provision (benefit).

On December 22, 2017, the President of the United States signed into law the Tax Cuts and Jobs Act of 2017 (the "Tax Act"). The SEC subsequently issued a Staff Accounting Bulletin No. 118, "Income Tax Accounting Implications of the Tax Cuts and Jobs Act" ("SAB 118"), which provides guidance on accounting for the tax effects of the Tax Act. Among other changes, the Tax Act lowered the corporate tax rate to 21%.

For the year ended December 31, 2020, the Company recorded a full valuation allowance against the deferred tax asset of $10,553,125. The Company was in a deferred tax asset position as a result of the ceiling test impairment recorded during 2020. No valuation allowance was recorded for the years ended December 31, 2019 or 2018.

Accounting for Uncertainty in Income Taxes – In accordance with generally accepted accounting principles, the Company has analyzed its filing positions in all jurisdictions where it is required to file income tax returns for the open tax years in such jurisdictions. The Company has identified its federal income tax return and its franchise tax return in Texas in which it operates as "major" tax jurisdictions. The Company's federal income tax returns for the years ended December 31, 2016 through 2019 remain subject to examination. The Company's franchise tax returns in Texas remain subject to examination for 2015 through 2019. The Company currently believes that all significant filing positions are highly certain and that all of its significant income tax filing positions and deductions would be sustained upon audit. Therefore, the Company has no significant reserves for uncertain tax positions and no adjustments to such reserves were required by generally accepted accounting principles. No interest or penalties have been levied against the Company and none are anticipated; therefore, no interest or penalty has been included in our provision for income taxes in the statements of operations.

Earnings (Loss) Per Share – Basic earnings (loss) per share is computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the year. Diluted earnings (loss) per share are calculated to give effect to potentially issuable dilutive common shares.

Major Customers – During the year ended December 31, 2020, sales to three customers represented 68%, 10% and 8%, respectively, of total oil and natural gas sales. As of December 31, 2020, sales outstanding from these three customers represented 80%, 0% and 5%, respectively, of accounts receivable. During the year ended December 31, 2019, sales to three customers represented 42%, 36% and 7%, respectively, of total oil and natural gas sales. As of December 31, 2019, sales outstanding from these three customers represented 47%, 31% and 9%, respectively, of accounts receivable. During the year ended December 31, 2018, sales to two customers represented 85% and 11%, respectively, of total oil and natural gas sales. As of December 31, 2018, sales outstanding from one customer made up 90% of accounts receivable. The loss of any of our customers would not have a material adverse effect on the Company as there is an available market for its oil and natural gas production from other purchasers.

Stock-Based Employee and Non-Employee Compensation – The Company has outstanding stock options to directors, employees and contract employees, which are described more fully in Note 13. The Company accounts for its stock options grants in accordance with generally accepted accounting principles. Generally accepted accounting principles require the recognition of the cost of services received in exchange for an award of equity instruments in the financial statements and is measured based on the grant date fair value of the award. Generally accepted accounting principles also requires stock option compensation expense to be recognized over the period during which an employee or non-employee is required to provide service in exchange for the award (the vesting period).

Stock-based compensation incurred for the years ended December 31, 2020, 2019 and 2018 was $5,364,162, $3,082,625 and $3,870,934, respectively.

Derivative Instruments and Hedging Activities - The Company may periodically enter into derivative contracts to manage its exposure to commodity risk. These derivative contracts, which are generally placed with major financial institutions, may take the form of forward contracts, futures contracts, swaps, or options. The oil and gas reference prices upon which the commodity derivative contracts are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company for its oil and natural gas production.

When applicable, the Company records all derivative instruments, other than those that meet the normal purchases and sales exception, on the balance sheet as either an asset or liability measured at fair value. Changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met.

Recently Adopted Accounting Pronouncements – In August 2018, the FASB issued Accounting Standards Updated ("ASU") 2018-13, *Fair Value Measurement (Topic 820): Changes to the Disclosure Requirements for Fair Value Measurement ("ASU 2018-13").* ASU 2018-13 eliminates, adds and modifies certain disclosure requirements for fair value measurement. ASU 2018-13 is effective for annual and interim periods beginning January 1, 2020, with early adoption permitted for either the entire standard or only the provisions that eliminate or modify requirements. ASU 2018-13 requires that the additional disclosure requirements be adopted using a retrospective approach. The adoption of this guidance did not have a material impact on the Company's financial statements.

Recent Accounting Pronouncements - In October 2020, the FASB issued ASU 2020-10, "Codification Improvements," which clarifies or improves disclosure requirements for various topics to align with Securities and Exchange Commission (SEC) regulations. This update is effective for the Company beginning in the first quarter of 2021 and will be applied retrospectively. The adoption and implementation of this ASU will not have a material impact on the Company's financial statements.

NOTE 2 – REVENUE RECOGNITION

Oil sales

Under the Company's oil sales contracts, the Company sells oil production at the point of delivery and collects an agreed upon index price, net of pricing differentials. The Company recognizes revenue when control transfers to the purchaser at the point of delivery at the net price received.

Natural gas sales

Under the Company's natural gas sales processing contracts for our Central Basin Platform properties, Delaware Basin properties and part of our Northwest Shelf assets, the Company delivers unprocessed natural gas to a midstream processing entity at the wellhead. The midstream processing entity obtains control of the natural gas at the wellhead. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sale of natural gas. Under these processing agreements, the Company recognizes revenue when control transfers to the purchaser at the point of delivery. As such, the Company accounts for any fees and deductions as a reduction of the transaction price.

Under the Company natural gas sales processing contracts for the bulk of our Northwest Shelf assets, the Company delivers unprocessed natural gas to a midstream processing entity at the well head. However, the Company maintains ownership of the gas through processing and receives proceeds from the marketing of the resulting products. Under this processing agreement, the Company recognizes the fees associated with the processing as an expense rather than netting these costs against revenue.

Disaggregation of Revenue. The following table presents revenues disaggregated by product:

	For the years ended December 31,		
	2020	2019	2018
Operating revenues			
Oil	$ 109,113,557	$ 191,891,314	$ 116,678,375
Natural gas	3,911,581	3,811,517	3,386,986
Total operating revenues	$ 113,025,138	$ 195,702,831	$ 120,065,361

NOTE 3 – LEASES

Effective January 1, 2019, the Company adopted ASU 2016-02, *Leases* (Topic 842). This guidance attempts to increase transparency and comparability among organizations by recognizing certain lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP methodology and the method in this new guidance is the recognition on the balance sheet of certain lease assets and lease liabilities by lessees for those leases that were classified as operating leases under previous GAAP.

The Company made accounting policy elections to not capitalize leases with a lease term of twelve months or less and to not separate lease and non-lease components for all asset classes. The Company has also elected to adopt the package of practical expedients within ASU 2016-02 that allows an entity to not reassess prior to the effective date (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases, or (iii) initial direct costs for any existing leases and the practical expedient regarding land easements that exist prior to the adoption of ASU 2016-02. The Company did not elect the practical expedient of hindsight when determining the lease term of existing contracts at the effective date.

The Company has operating leases for our offices in Midland, Texas and Tulsa, Oklahoma. The Midland office is under a five-year lease beginning January 1, 2021. The Tulsa lease is month-to-month but the Company does not intend to continue use of this office. As of December 31, 2019, the Company did intend to continue use of the Tulsa office and, as such, the lease costs associated with the Tulsa lease has been accounted for as operating leases with a term that end on December 31, 2020. However, it is not reflected in future lease payments as it is now a short-term lease. The office space being leased in Tulsa is owned by Arenaco, LLC, a company that is owned by Mr. Rochford, former Chairman of the Board of the Company, and Mr. McCabe, a former Director of the Company. Subsequent to December 31, 2020, the Company entered into a lease for office space in The Woodlands, Texas. The future payments associated with this lease are not reflected below.

The Company also has month to month leases for office equipment and compressors used in our operations on which the Company has elected to apply ASU 2016-02. While these leases are month to month, the Company intends to continue these leases for the useful life of the assets. As such, these leases have been accounted for as if the lease term lasts through the estimated useful life of the assets.

The Company also has month to month leases or other short-term leases for equipment used in our operations on which the Company has made accounting policy elections not to capitalize these leases. These leases are for terms that are less than 12 months and the Company does not intend to continue to lease this equipment for more than 12 months. The lease costs associated with these leases is reflected in the short-term lease costs below.

The Company also has financing leases for vehicles. These leases have a term of36 months at the end of which the Company owns the vehicles. These vehicles are generally sold at the end of their term and the proceeds applied to a new vehicle .

Future lease payments associated with these operating and financing leases as of December 31, 2020 are as follows:

	2021	2022	2023	2024	2025
Operating lease payments (1)	$ 909,035	$ 186,127	$ 178,377	$ 164,527	$ 164,527
Financing lease payments (2)	311,206	132,499	—	—	—

(1) The weighted average discount rate as of December 31, 2020 for operating leases was4.50%. Based on this rate, the future lease payments above include imputed interest of $108,195. The weighted average remaining term of operating leases was3.0 years.

(2) The weighted average discount rate as of December 31, 2020 for financing leases was5.26%. Based on this rate, the future lease payments above include imputed interest of $21,538. The weighted average remaining term of financing leases was1.42 years.

The following table provides supplemental information regarding cash flows from operations:

	2020
Operating lease costs	$ 1,196,373
Short term lease costs (1)	5,337,433
Financing lease costs:	
Amortization of financing lease assets (2)	287,413
Interest on lease liabilities (3)	30,237

(1) Amount included in Oil and gas production costs

(2) Amount included in Depreciation, depletion and amortization

(3) Amount included in Interest expense

NOTE 4 – EARNINGS (LOSS) PER SHARE INFORMATION

For the years ended December 31,	2020	2019	2018
Net Income (Loss)	$ (253,411,828)	$ 29,496,551	$ 8,999,760
Basic Weighted-Average Shares Outstanding	72,891,310	66,571,738	59,531,200
Effect of dilutive securities:			
Stock options	—	174,944	1,238,786
Restricted stock	—	10,346	78,191
Common warrants	—	—	—
Diluted Weighted-Average Shares Outstanding	72,891,310	66,757,028	60,848,177
Basic Earnings (Loss) per Share	$ 3.48	$ 0.44	$ 0.15
Diluted Earnings (Loss) per Share	$ 3.48	$ 0.44	$ 0.15

Stock options to purchase 465,500, 2,353,500 and 574,500 shares of common stock were excluded from the computation of diluted earnings per share during the years ended December 31, 2020, 2019 and 2018, respectively, as their effect would have been anti-dilutive. 2,144,617, 704,684 and 2,500 shares of unvested restricted stock were excluded from the computation of diluted earnings per share during the years ended December 31, 2020, 2019 and 2018, respectively, as their effect would have been anti-dilutive. Common warrants to purchase 29,804,300 shares of common stock were excluded from the computation of diluted earnings per share during the year ended December 31, 2020, as their effect would have been anti-dilutive.

Pre-funded warrants to purchase 13,428,500 shares of common stock were included in the calculation of the Basic Weighted-Average Shares Outstanding as they are exercisable for a nominal amount and so are treated as if they were exercised at issuance.

NOTE 5 – ACQUISITIONS

In December 2018, Ring completed the acquisition of oil and natural gas assets and properties in assets in Andrews County. The acquired properties consist of 4,854 gross (4,788 net) acres and include a 100% working interest and a 75% net revenue interest. Consideration given by the Company consisted of 2,623,948 shares valued at $5.80 per share for an aggregate value of $11,204,258 and liabilities assumed of $2,571,549. The Company incurred approximately $23,321 in acquisition related costs, which were recognized in general and administrative expense during the year ended December 31, 2018.

The acquisition was recognized as a business combination whereby Ring recorded the assets acquired and the liabilities assumed at their fair values as of November 1, 2018, which is the date the Company obtained control of the properties and was the acquisition date for financial reporting purposes.

The estimated fair value of the acquired properties approximated the consideration paid, which the Company concluded approximated the fair value that would be paid by a typical market participant. The following table summarizes the fair values of the assets acquired and the liabilities assumed:

Assets acquired		
Proved oil and natural gas properties	$	13,775,807
Liabilities assumed		
Asset retirement obligations		(2,571,549)
Total Identifiable Net Assets	$	11,204,258

On April 9, 2019, the Company completed the acquisition of oil and gas properties from Wishbone Energy Partners, LLC, Wishbone Texas Operating Company LLC and WB WaterWorks LLC on the Northwest Shelf in Gaines, Yoakum, Runnels and Coke Counties, Texas and Lea County, New Mexico (the "Acquisition"). The acquired properties consist of 49,754 gross (38,230 net) acres and include a 77% average working interest and a 58% average net revenue interest. Ring executed the Acquisition for the existing production and future development potential. The Company incurred approximately $4.1 million in acquisition related costs, which were recognized in general and administrative expense. Total consideration after purchase price adjustments included cash payments totaling approximately $276.1 million and the issuance of 4,576,951 shares of common stock, of which 2,538,071 shares were placed in escrow to satisfy potential indemnification claims. One half of the shares placed into escrow remain in escrow as of December 31, 2019. The range of potential outcomes regarding the indemnification escrow shares cannot be determined as the Company evaluates whether there are any claims against the indemnification. If no claims are made, the remaining escrow shares will be released pursuant to the terms of the Purchase and Sale Agreement. The shares were valued at the price on the date of the signing of the Purchase and Sale Agreement, February 25, 2019, of $6.19 per share.

The Acquisition was recognized as a business combination whereby Ring recorded the assets acquired and the liabilities assumed at their fair values as of February 1, 2019, which is the date the Company obtained control of the properties and was the acquisition date for financial reporting purposes. The Company determined that it had effective control of the properties effective February 1, 2019 based on Ring having primary decision making ability regarding the properties beginning at that time. Revenues and related expenses for the Acquisition are included in our condensed statements of operations beginning February 1, 2019. The estimated fair value of the acquired properties approximated the consideration paid, which the Company concluded approximated the fair value that would be paid by a typical market participant. The following table summarizes the fair values of the assets acquired and the liabilities assumed:

Assets acquired:		
Proved oil and natural gas properties	$	305,004,775
Joint interest billing receivable		1,464,394
Prepaid assets		2,864,554
Liabilities assumed		
Accounts and revenues payable		(1,234,861)
Asset retirement obligations		(3,705,941)
Total Identifiable Net Assets	$	304,392,921

The revenues and direct operating costs associated with the acquired properties included in our financial statements for the year ended December 31, 2019 are as follows:

Revenue	$	105,102,038
Oil and natural gas production costs		17,037,228
Oil and natural gas production taxes		4,646,660
Total direct costs (1)		21,683,888
Earnings from the Acquired properties	$	83,418,150

(1) This includes only oil and natural gas production costs and oil and natural gas production taxes and does not give account to depreciation, depletion and amortization, accretion of asset retirement obligation, general and administrative expense, interest expense or any other cost that cannot be directly correlated to the Acquisition.

The following unaudited pro forma information for the years ended December 30, 2019 and 2018, respectively, is presented to reflect the operations of the Company as if the acquisition of assets had been completed on January 1, 2019 and 2018, respectively:

For the years ended December 31,	2019	2018
Oil and Natural Gas Revenues	$ 202,368,245	$ 196,385,905
Net Income	$ 29,556,993	$ 29,105,827
Basic Earnings per Share	$ 0.44	$ 0.49
Diluted Earnings per Share	$ 0.44	$ 0.48

NOTE 6 – DEPOSIT FORFEITURE INCOME

In the fourth quarter of 2020, the Company entered into an agreement with an intended buyer to sell the Company's Delaware assets. The agreement was amended on six different occasions throughout 2020 releasing the initial deposits to the Company and requiring additional non-refundable deposits. In total, $5,500,000 in non-refundable deposits were made to the Company. In October 2020, the agreement was terminated as the buyer was not able to consummate the transaction. As such, the Company recognized the $5,500,000 as income in our Statements of Operations as no divestiture of assets had occurred.

NOTE 7 – OIL AND NATURAL GAS PRODUCING ACTIVITIES

Set forth below is certain information regarding the aggregate capitalized costs of oil and natural gas properties and costs incurred by the Company for its oil and natural gas property acquisitions, development and exploration activities:

As of December 31,	2020	2019
Proved oil and natural gas properties	$ 836,514,815	$ 1,083,966,135
Financing lease asset subject to depreciation	858,513	858,513
Fixed assets subject to depreciation	1,520,890	1,465,551
Total capitalized costs	838,894,218	1,086,290,199
Accumulated depletion, depreciation and amortization	(200,111,658)	(157,074,044)
Net Capitalized Costs	$ 638,782,560	$ 929,216,155

Net Costs Incurred in Oil and Gas Producing Activities

For the years Ended December 31,	2020	2019
Payments for the Wishbone Acquisition	$ —	$ 276,061,594
Payments to purchase oil and natural gas properties	1,317,313	3,400,411
Proceeds from divestiture of oil and natural gas properties	—	(8,547,074)
Payments to develop oil and natural gas properties	42,457,745	152,125,320
Payments to acquire or improve fixed assets subject to depreciation	55,339	—
Total Net Costs Incurred	$ 43,830,397	$ 423,040,251

NOTE 8 – DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to fluctuations in crude oil and natural gas prices on its production. We can utilize derivative strategies that consist of either a single derivative instrument or a combination of instruments to manage the variability in cash flows associated with the forecasted sale of our future domestic oil and natural gas production. While the use of derivative instruments may limit or partially reduce the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements.

From time to time the Company enters into derivative contracts to protect the Company's cash flow from price fluctuation and maintain its capital programs. The Company uses either costless collars or swaps for this purpose. Oil derivative contracts are based on WTI Crude Oil prices and natural gas contacts are based on Henry Hub. A "costless collar" is the combination of two options, a put option (floor) and call option (ceiling) with the options structured so that the premium paid for the put option will be offset by the premium received from selling the call option. Similar to costless collars, there is no cost to enter into the swap contracts. On swap contracts, there is no spread and payments will be made or received based on the difference between WTI and the swap contract price.

The following table provides information as to derivative contracts for WTI that were in place during the years ended December 31, 2020, 2019 and 2018. The Company did not have any natural gas derivative contracts during these years.

Date entered into	Period covered	Barrels per day	Put price	Call price	Swap price
2018 costless collars					
09/25/17	Calendar year 2018	1,000	$ 49.00	$ 54.60	
10/27/17	Calendar year 2018	1,000	51.00	54.80	
2019 costless collars					
8/27/2018 (1)	Calendar year 2019	2,000	60.00	70.05	
2020 costless collars					
04/01/19	Calendar year 2020 (2)	1,000	50.00	65.83	
04/01/19	Calendar year 2020 (2)	1,000	50.00	65.40	
11/05/19	Calendar year 2020 (2)	1,000	50.00	58.40	
11/07/19	Calendar year 2020 (2)	1,000	50.00	58.25	
11/11/19	Calendar year 2020 (2)	1,500	50.00	58.65	
2020 swaps					
05/29/20	June 2020 and July 2020 (2)	5,500			$ 33.24

(1) On October 10, 2018, the Company terminated the costless collars for calendar year 2019 through the payment of $3,438,300.

(2) On May 29, 2020, the Company unwound the costless collars for June 2020 and July 2020, resulting in the receipt of a cash payment of $5,435,136. Concurrently, the Company entered into swap contracts at $33.24 for 5,500 barrels per day for June and July 2020, equal to the barrels for which the costless collars were unwound.

Throughout 2020, the Company entered into additional derivative contracts in the form of costless collars and swaps for 2021 and 2022 for both oil and natural gas. The following tables reflect the details of those contracts:

Date entered into	Period covered	Barrels per day	Put price	Call price	Swap price
Oil derivative contracts					
2021 costless collars					
02/25/20	Calendar year 2021	1,000	$ 45.00	$ 54.75	
02/25/20	Calendar year 2021	1,000	45.00	52.71	
02/27/20	Calendar year 2021	1,000	40.00	55.08	
03/02/20	Calendar year 2021	1,500	40.00	55.35	
2021 swaps					
11/25/20	Calendar year 2021	2,000			$ 45.37
12/02/20	Calendar year 2021	500			45.38
12/03/20	Calendar year 2021	500			45.00
12/04/20	Calendar year 2021	500			45.40
12/04/20	Calendar year 2021	500			45.60
12/07/20	Calendar year 2021	500			45.96
2022 swaps					
12/04/20	Calendar year 2022	500			44.22
12/07/20	Calendar year 2022	500			44.75
12/10/20	Calendar year 2022	500			44.97
12/17/20	Calendar year 2022	250			45.98

Date entered into	Period covered	MMBTU per day	Swap price
Natural gas derivative contracts			
2021 swaps			
11/04/20	Calendar year 2021	6,000	$ 2.991
2022 swaps			
11/04/20	Calendar year 2022	5,000	2.7255

Derivative financial instruments are recorded at fair value and included as either assets or liabilities in the accompanying balance sheets. Any gains or losses resulting from changes in fair value of outstanding derivative financial instruments and from the settlement of derivative financial instruments are recognized in earnings and included as a component of other income in the accompanying statements of operations.

The use of derivative transactions involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. All previous derivative contracts have been with lenders under our credit facility.

NOTE 9 – FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value and requires that fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy. We continue to evaluate our inputs to ensure the fair value level classification is appropriate. When transfers between levels occur, it is our policy to assume that the transfer occurred at the date of the event or change in circumstances that caused the transfer.

As a result of the Wishbone Acquisition, the Company evaluated the fair value of the assets acquired and the liabilities assumed. The Company recorded the oil and gas assets acquired in the Wishbone Acquisition at the price paid. Prior to doing so, the Company determined that the price paid approximated the fair value of the net assets acquired. In doing so, the Company compared the price paid per BOE of existing production to comparable companies enterprise value per BOE of existing production. Additionally, the Company did an evaluation of the reserves acquired, based on varying percentages of the present value discounted at 10 percent (PV-10) of the different categories (PDP, PDNP and PUD) of the reserves. Based on these evaluations, we determined that the price paid was a reasonable approximation of the fair value of the oil and gas assets acquired. Given the significance of the unobservable nature of a number of the inputs, these are considered Level 3 on the fair value hierarchy.

The Company recorded the prepaid expenses, joint interest billing receivables and revenues payable at the carrying value assumed from Wishbone. The carrying amounts of receivables and accounts payable and other current assets and liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities.

The fair values of the Company's derivatives are not actively quoted in the open market. The Company uses a market approach to estimate the fair values of its derivative instruments on a recurring basis, utilizing commodity futures pricing for the underlying commodities provided by a reputable third party, a Level 2 fair value measurement.

The following table summarizes the valuation of our assets and liabilities that are measured at fair value on a recurring basis.

	Fair Value Measurement Classification			
	Quoted prices in Active Markets for Identical Assets or (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of December 31, 2018				
Oil and gas derivative contracts	$ —	$ —	$ —	$ —
Total	$ —	$ —	$ —	$ —
As of December 31, 2019				
Oil and gas derivative contracts	$ —	$ (3,000,078)	$ —	$ (3,000,078)
Total	$ —	$ (3,000,078)	$ —	$ (3,000,078)
As of December 31, 2020				
Oil and gas derivative contracts	$ —	$ (4,156,601)	$ —	$ (4,156,601)
Total	$ —	$ (4,156,601)	$ —	$ (4,156,601)

NOTE 10 – REVOLVING LINE OF CREDIT

On July 1, 2014, the Company entered into a Credit Agreement with SunTrust Bank, as lender, issuing bank and administrative agent for several banks and other financial institutions and lenders (the “Administrative Agent”), which was amended on April June 14, 2018, May 18, 2016, July 24, 2015, and June 26, 2015. In April 2019, the Company amended and restated its Credit Agreement with the Administrative Agent (as amended and restated, the “Credit Facility”). The amendment and restatement of the Credit Facility, among other things, increases the maximum borrowing amount to $1 billion, extends the maturity date through April 2024 and makes other modifications to the terms of the Credit Facility. This Credit Facility was amended on December 23, 2020 and June 17,2020. The latest amendment adjusted the borrowing base to $350 million and made other modifications to the terms of the Credit Facility. The Credit Facility is secured by a first lien on substantially all of the Company’s assets.

The Borrowing Base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The Borrowing Base will be redetermined semi-annually on each May 1 and November 1. The Borrowing Base will also be reduced in certain circumstances such as the sale or disposition of certain oil and gas properties of the Company or its subsidiaries and cancellation of certain hedging positions.

The Credit Facility allows for Eurodollar Loans and Base Rate Loans (as respectively defined in the Credit Facility). The interest rate on each Eurodollar Loan will be the adjusted LIBOR for the applicable interest period plus a margin between 2.5% and 3.5% (depending on the then-current level of Borrowing Base usage). The annual interest rate on each Base Rate Loan is (a) the greatest of (i) the Administrative Agent’s prime lending rate, (ii) the Federal Funds Rate (as defined in the Credit Facility) plus 0.5% per annum, (iii) the adjusted LIBOR determined on a daily basis for an interest period of one-month, plus 1.00% per annum and (iv) 0.00% per annum, plus (b) a margin between 1.5% and 2.5% (depending on the then-current level of Borrowing Base usage).

The Credit Facility contains certain covenants, which, among other things, require the maintenance of (i) a total Leverage Ratio (outstanding debt to adjusted earnings before interest, taxes, depreciation and amortization) of not more than 4.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Credit Facility) of 1.0 to 1.0. The amendment to the credit facility in June 2020 allowed for a Leverage Ratio of not greater than 4.75 to 1 as of the last day of the fiscal quarter ending September 30, 2020. The December 2020 amendment permitted a total Leverage Ratio not greater than 4.25 for the period ending March 31, 2021. The Credit Facility also contains other customary affirmative and negative covenants and events of default. As of December 31, 2020, $313,000,000 was outstanding on the Credit Facility. We are in compliance with all covenants contained in the Credit Facility.

NOTE 11 – ASSET RETIREMENT OBLIGATION

A reconciliation of the asset retirement obligation for the years ended December 31, 2018, 2019 and 2020 is as follows:

Balance, December 31, 2017	$	9,055,697
Liabilities acquired	$	2,571,549
Liabilities incurred		1,311,956
Liabilities settled		(577,824)
Revision of estimate (1)		87,960
Accretion expense		606,459
Balance, December 31, 2018	$	13,055,797
Liabilities acquired	$	3,745,642
Liabilities incurred		631,727
Liabilities settled		(1,589,654)
Accretion expense		943,707
Balance, December 31, 2019	$	16,787,219
Liabilities incurred		99,436
Liabilities settled		(710,577)
Revision of estimate (1)		34,441
Accretion expense		906,616
Balance, December 31, 2020	$	17,117,135

(1) Several factors are considered in the annual review process, including current estimates for removal cost and estimated remaining useful life of the assets. The 2018 revision of estimates reflect decreases in the estimated remaining useful life of certain assets. The 2020 revision of estimates reflect an adjustment to the estimates for plugging costs.

NOTE 12 – STOCKHOLDERS' EQUITY

The Company is authorized to issue 150,000,000 common shares, with a par value of $0.001 per share and 50,000,000 shares of Preferred Stock.

Issuance of equity instruments in public and private offerings – In February 2018, the Company closed on an underwritten public offering of 6,164,000 shares of its common stock, including 804,000 shares sold pursuant to the full exercise of an over-allotment option, at $14.00 per share for gross proceeds of $86,296,000. Total net proceeds from the offering were $81,821,138, after deducting underwriting commissions and offering expenses payable by the Company of $4,474,862.

In October 2020, the Company closed on an underwritten public offering of (i) 9,575,800 Common Shares, (ii) 13,428,500 Pre-Funded Warrants and (iii) 23,004,300 Common Warrants at a combined purchase price of $0.70. This includes a partial exercise of the over-allotment. The Common Warrants have a term of five years and an exercise price of $0.80 per share. Gross proceeds totaled $16,089,582.

Concurrently with the underwritten public offering, the Company closed on a registered direct offering of (i) 3,500,000 Common Shares, (ii) 3,300,000 Pre-Funded Warrants and (iii) 6,800,000 Common Warrants at a combined purchase price of $0.70 per Common Share and Pre-Funded Warrant. The Common Warrants have a term of five years and an exercise price of $0.80 per share. Gross proceeds totaled $4,756,700.

Total gross proceeds from the 2020 underwritten public offering and the registered direct offering aggregated $20,846,282. Total net proceeds aggregated $19,379,832.

Common stock issued pursuant to warrant exercise - In December 2020, the Company issued 3,300,000 shares of common stock pursuant to the exercise of pre-funded warrants issued in the October 2020 registered direct offering. Gross and net proceeds were $3,300.

Common stock issued in property acquisition – As discussed in Note 5, in December 2018, the Company issued 2,623,948 shares of common stock as consideration for the acquisition of oil and natural gas properties. These shares were valued at $5.80 per share for an aggregate of $11,204,258.

Also as discussed in Note 5, in April 2019, the Company completed the acquisition of assets from Wishbone Partners, LLC. As a part of the consideration for the acquisition, the Company issued 4,576,951 shares of common stock. The shares were valued at February 25, 2019, the date of the signing of the Purchase and Sale Agreement. The price on February 25, 2019 was $6.19 per share. The aggregate value of the shares issued, based on this price, was $28,331,327.

In April 2020, 16,702 shares were returned and cancelled as settlement of post-closing adjustments. The shares were valued at February 25, 2019, the date of the signing of the Purchase and Sale Agreement. The price on February 25, 2019 was $6.19 per share. The aggregate value of the shares returned, based on this price, was $103,385.

Common Stock Issued for option exercises – During the year ended December 31, 2018, the Company issued 153,113 shares of common stock as a result of option exercises. No options were exercised in 2019 or 2020. The following tables present the details of the 2018 exercises:

	Options exercised	Exercise price ($)	Shares issued	Shares retained	Cash paid at exercise ($)	Stock price on date of exercise ($)	Aggregate value of shares retained ($)
2018	110,000	$ 2.00	90,375	19,625	$ —	$ 11.21	$ 220,000
	50,000	2.00	50,000	—	100,000	8.00	—
	25,000	7.50	9,829	15,171	—	12.36	$ 187,500
	3,000	8.00	1,059	1,941	—	12.36	$ 24,000
	3,000	5.25	1,750	1,250	—	12.36	$ 15,750
	2,000	11.75	100	1,900	—	12.36	$ 23,500
2018 Totals	193,000		153,113	39,887	$ 100,000		$ 470,750
2018 Weighted Averages		$ 2.96				$ 10.58	

NOTE 13 – EMPLOYEE STOCK OPTIONS, RESTRICTED STOCK AWARD PLAN AND 401(k)

In June 2020, officers and directors of the Company voluntarily returned stock options that had previously been granted to them. In total 2,265,000 options with a weighted average exercise price of $6.87 per share were returned to and cancelled by the Company. No grants, cash payments or other consideration has been or will be made to replace the options or otherwise in connection with the return. As a result of the return and cancellation of the options, the Company incurred additional compensation expense of $768,379.

During October and December 2020, as a result of changes to the executive team and the Board of Directors, the Company accelerated the vesting of 1,131,955 shares of restricted stock. As a result of the acceleration of these vestings, the Company incurred additional compensation expense of $2,361,362.

Compensation expense charged against income for share-based awards during the years ended December 31, 2020, 2019 and 2018 was $5,364,162, $3,082,625 and $3,870,934, respectively. These amounts are included in general and administrative expense in the accompanying Statements of Operations.

In 2011, the Company's Board of Directors approved and adopted a long-term incentive plan, which was subsequently approved and amended by the shareholders. There were 341,155 shares eligible for grant, either as options or as restricted stock, as of December 31, 2020.

Employee Stock Options – No options have been granted in the years ended December 31, 2020, 2019 or 2018. All granted options vest at the rate of 20% each year over five years beginning one year from the date granted and expire ten years from the grant date.

A summary of the status of the stock options as of December 31, 2020, 2019 and 2018 and changes during the years ended December 31, 2020, 2019 and 2018 is as follows:

	2020		2019		2018	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of the year	2,748,500	$ 6.28	2,751,000	$ 6.28	3,193,000	$ 6.07
Issued	—	—	—	—	—	—
Forfeited or rescinded	(2,283,000)	6.89	(2,500)	11.70	(249,000)	6.09
Exercised	—	—	—	—	(193,000)	2.96
Outstanding at end of year	465,500	$ 3.26	2,748,500	$ 6.28	2,751,000	$ 6.28
Exercisable at end of year	455,300	$ 3.11	2,506,700	$ 5.78	2,323,900	$ 5.42

For the years ended December 31, 2020, 2019 and 2018, the Company incurred stock-based compensation expense related to stock options of $927,559, $625,855 and $1,853,913, respectively. As of December 31, 2020, there was $14,988 of unrecognized compensation cost related to stock options that will be recognized over a weighted average period of 0.6 years. The aggregate intrinsic value of options vested and expected to vest as of December 31, 2020 was $0. The aggregate intrinsic value of options exercisable at December 31, 2020 was $0. The year-end intrinsic values are based on a December 31, 2020 closing price of $0.66.

Options exercised of 193,000 in 2018 had an aggregate intrinsic value on the date of exercise of $1,470,230. No options were exercised in 2020 or 2019.

The following table summarizes information related to the Company's stock options outstanding as of December 31, 2020:

	Options Outstanding		
Exercise price	Number Outstanding	Weighted-Average Remaining Contractual Life (in years)	Number Exercisable
2.00	395,000	2.92	395,000
5.50	5,000	2.20	5,000
14.54	10,000	3.73	10,000
8.00	4,500	3.92	4,500
6.42	15,000	5.34	12,000
11.75	36,000	5.95	28,800
	465,500	3.25	455,300

Restricted stock grants – Following is a table reflecting the restricted stock grants during 2018, 2019 and 2020:

Grant date	# of shares of restricted stock
April 4, 2018	2,000
September 27, 2018	2,500
December 26, 2018	615,380
April 9, 2019	10,400
May 30, 2019	5,000
July 9, 2019	5,000
September 13, 2019	10,000
December 21, 2019	627,205
October 1, 2020	900,000
October 26, 2020	150,000
December 15, 2020	930,000

Restricted stock grants prior to 2020 vest at the rate of20% each year over five years beginning one year from the date granted. Restricted stock grants in 2020 vest at a rate of 33% each year over three years beginning one year from the date granted. A summary of the status of restricted stock grants as of December 31, 2020, 2019 and 2018 and changes during the years ended December 31, 2020, 2019 and 2018 is as follows:

	2020		2019		2018	
	Restricted stock	Weighted-Average Grant Date Fair Value	Restricted stock	Weighted-Average Grant Date Fair Value	Restricted stock	Weighted-Average Grant Date Fair Value
Outstanding at beginning of the year	1,341,889	$ 4.99	878,360	$ 7.33	330,900	$ 13.44
Granted	1,980,000	0.71	657,605	2.63	619,880	4.78
Forfeited or rescinded	(9,200)	3.97	(6,940)	4.23	(7,800)	13.44
Vested	(1,180,392)	4.97	(187,136)	7.79	(64,620)	13.44
Outstanding at end of year	2,132,297	$ 2.94	1,341,889	$ 4.99	878,360	$ 7.33

For the years ended December 31, 2020, 2019 and 2018, the Company incurred stock-based compensation expense related to restricted stock grants of $4,436,603, $2,456,770 and $2,017,021, respectively. As of December 31, 2020, there was $1,520,839 of unrecognized compensation cost related to restricted stock grants that will be recognized over a weighted average period of 1.5 years.

During 2020, 2019 and 2018, 1,180,392, 187,136 and 64,620 shares of restricted stock vested, respectively. At the dates of vesting those shares had an aggregate intrinsic value of $801,133, $494,605 and $304,360, respectively.

401(k) Plan- In 2019, the Company initiated a sponsored 401(k) plan that is a defined contribution plan for the benefit of all eligible employees. The plan allows eligible employees, after a three-month waiting period, to make pre-tax or after-tax contributions of up to 100% of their annual eligible compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of any employee's compensation. Employees are 100% vested in the employer contribution upon receipt.

The following table presents the matching contributions expense recognized for the Company's 401(k) plan for the years ended December 31, 2020 and 2019. There were no matching contributions prior to 2019.

	2020	2019
Employer safe harbor match	138,977	59,716

NOTE 14 – RELATED PARTY TRANSACTIONS

The Company is leasing office space from Arenaco, LLC, a company that is owned by two stockholders' of the Company, Mr. Rochford, former Chairman of the Board of the Company, and Mr. McCabe , a former Director of the Company. During the years ended December 31, 2020, 2019 and 2018, the Company paid $60,000, $60,000 and $60,000, respectively, to this company.

NOTE 15 – COMMITMENTS AND CONTINGENT LIABILITIES

Standby Letters of Credit – A commercial bank issued standby letters of credit on behalf of the Company totaling $260,000 to state and federal agencies and $500,438 to an insurance company to secure the surety bonds described below. The standby letters of credit are valid until cancelled or matured and are collateralized by the revolving credit facility with the bank. The terms of the letters of credit to the state and federal agencies are extended for a term of one year at a time. The Company intends to renew the standby letters of credit to the state and federal agencies for as long as the Company does business in the States of Texas and New Mexico. The letters of credit to the insurance company will be renewed if the insurance requires them to retain the surety bonds. No amounts have been drawn under the standby letters of credit.

Surety Bonds – An insurance company issued surety bonds on behalf of the Company totaling $500,438 to various State of New Mexico agencies in order for the Company to do business in the State of New Mexico. The surety bonds are valid until canceled or matured. The terms of the surety bonds are extended for a term of one year at a time. The Company intends to renew the surety bonds on $400,000 as long as the Company does business in the State of New Mexico. The remaining $100,438 will require renewal until the two subject wells are plugged.

NOTE 16 – INCOME TAXES

For the years ended December 31, 2020, 2019 and 2018, components of our provision for income taxes are as follows:

Provision for (Benefit from) Income Taxes	**2020**	**2019**	**2018**
Deferred taxes	$ (6,001,176)	$ 13,787,654	$ 3,445,721
Provision for (Benefit from) Income Taxes	$ (6,001,176)	$ 13,787,654	$ 3,445,721

The following is a reconciliation of income taxes computed using the U.S. federal statutory rate to the provision for income taxes:

Rate Reconciliation	**2020**	**2019**	**2018**
Tax at federal statutory rate	$ (54,476,731)	$ 9,089,683	$ 2,613,551
Non-deductible expenses	956	2,399	3,197
Excess tax benefit from stock option exercises and restricted stock vesting	(1,109,379)	4,055,418	828,973
Adjust prior estimates to tax return	(4,754)	19	—
States taxes, net of Federal benefit	(964,393)	160,913	—
Adjustment for change in future effective tax rate(1)	—	479,222	—
Valuation allowance (2)	50,553,125	—	—
Provision for Income Taxes	$ (6,001,176)	$ 13,787,654	$ 3,445,721

(1) The acquisition of the Northwest Shelf assets from Wishbone included properties in the State of New Mexico. The tax rates associated with the State of New Mexico adjusted our overall tax rate from 21% to 21.29%. This resulted in an additional tax expense during the year ended December 31, 2019 of $479,222.

(2) As a result of the ceiling test impairments recorded in 2020, a benefit from income tax provision was recorded resulting in a deferred tax asset. The Company recorded a full valuation allowance against the deferred tax asset of $50,553,125.

The net deferred taxes consisted of the following as of December 31, 2020 and 2019:

Deferred Taxes:	**2020**	**2019**
Deferred tax liabilities		
Property and equipment	$ 5,357,255	$ 56,325,029
Deferred tax assets		
Stock-based compensation	2,248,272	269,264
Operating loss and IDC carryforwards	3,108,983	50,054,589
Deferred tax assets	5,357,255	50,323,853
Net deferred income tax liability	$ —	$ 6,001,176

As of December 31, 2020, the Company had net operating loss carry forwards for federal income tax reporting purposes of approximately $107.4 million which, if unused, will begin to expire in 2027 and fully expire in 2038 and an additional $150.2 million that will not expire.

NOTE 17 – QUARTERLY FINANCIAL DATA (UNAUDITED)

	2018			
	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
Revenues	$ 29,891,391	$ 29,924,883	$ 32,687,179	$ 27,561,908
Operating Income (Loss)	10,935,120	9,397,559	9,615,030	(9,986,770)
Net Income (Loss)	5,665,634	4,719,806	5,693,628	(7,079,308)
Basic Net Income (Loss) Per Share	$ 0.10	$ 0.08	$ 0.09	$ (0.12)
Diluted Net Income (Loss) Per Share	0.10	0.08	0.09	$ (0.12)

	2019			
	Three Months Ended			
	March 31 (restated)	**June 30 (restated)**	**September 30 (restated)**	**December 31**
Revenues	$ 41,798,315	$ 51,334,225	$ 50,339,105	$ 52,231,186
Operating Income	10,235,485	17,636,415	14,342,410	17,922,018
Net Income	4,269,260	11,342,597	8,858,000	5,026,692
Basic Net Income Per Share	$ 0.07	$ 0.17	$ 0.13	$ 0.08
Diluted Net Income Per Share	0.07	0.17	0.13	$ 0.08

	2020			
	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
Revenues	$ 39,570,328	$ 10,636,593	$ 31,466,544	$ 31,351,673
Operating Income (Loss)	10,081,718	(156,845,697)	6,511,161	(128,408,648)
Net Income (Loss)	43,804,118	(135,000,066)	(1,961,603)	(160,254,277)
Basic Net Income (Loss) Per Share	$ 0.64	$ (1.99)	$ (0.03)	$ (1.83)
Diluted Net Income (Loss) Per Share	0.64	(1.99)	(0.03)	(1.83)

NOTE 18 – LEGAL MATTERS

In the ordinary course of business, we may be, from time to time, a claimant or a defendant in various legal proceedings. We do not presently have any material litigation pending or threatened requiring disclosure under this item.

NOTE 19 – SUBSEQUENT EVENTS

The Company entered into a Sublease Agreement dated January 15, 2021, covering approximately15,728 square feet at 1725 Hughes Landing Blvd, Suite 900, The Woodlands, TX 77380. The sublease term will run until July 31, 2026.

The Company entered into a Purchase, Sale and Exchange Agreement dated February 1, 2021, effective January 1, 2021, with Vin Fisher Operating, Inc. covering the sale and exchange of certain oil and gas interests in Andrews County, Texas. After the sale and transfer of wells and leases between the two parties, the Company also received cash consideration of $2,000,000. The deal greatly reduces the Company's plug and abandonment obligation costs and also allows the Company to acquire new leasehold for the future drilling of additional horizontal wells.

Subsequent to December 31, 2020, the remaining13,428,500 Pre-Funded warrants and 184,800 of the Common Warrants issued in the October 2020 offering were exercised. Gross proceeds were $161,269.

RING ENERGY, INC.
SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES
(Unaudited)

Results of Operations from Oil and Natural Gas Producing Activities – The Company's results of operations from oil and natural gas producing activities exclude interest expense, gain from change in fair value of put options, and other financing expense. Income taxes are based on statutory tax rates, reflecting allowable deductions.

For the years ended December 31,	2020	2019	2018
Oil and natural gas sales	$ 113,025,138	$ 195,702,831	$ 120,065,361
Production costs	(36,968,873)	(48,496,225)	(27,801,989)
Production taxes	(5,228,090)	(9,130,379)	(5,631,093)
Depreciation, depletion, amortization and accretion	(43,010,660)	(56,204,269)	(39,024,886)
Ceiling test impairment	(277,501,943)	—	(14,172,309)
General and administrative (exclusive of corporate overhead)	(1,454,041)	(5,696,189)	(1,404,635)
Results of Oil and Natural Gas Producing Operations	$ (251,138,469)	$ 76,175,769	$ 32,030,449

Reserve Quantities Information – The following estimates of proved and proved developed reserve quantities and related standardized measure of discounted future net cash flow are estimates only, and do not purport to reflect realizable values or fair market values of the Company's reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company's reserves are located in the United States of America.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and methods.

The standardized measure of discounted future net cash flows is computed by applying the price according to the SEC guidelines for oil and natural gas to the estimated future production of proved oil and natural gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows.

For the Year Ended December 31,	2020		2019	
	Oil (1)	**Natural Gas (1)**	**Oil (1)**	**Natural Gas (1)**
Proved Developed and Undeveloped Reserves				
Beginning of year	71,359,014	58,271,882	27,809,748	52,765,698
Purchases of minerals in place	—	—	36,501,824	41,921,368
Improved recovery	3,495,210	1,824,310	4,732,449	2,530,636
Extensions and discoveries	—	—	13,295,301	5,501,627
Sale of minerals in place	—	—	(758,169)	(811,279)
Production	(2,801,528)	(2,494,501)	(3,536,126)	(2,476,472)
Upward revision of estimate	2,591,965	6,158,076	2,731,228	1,618,234
Downward revision of estimate due to well performance	(4,484,425)	44,370	(3,699,908)	(11,680,453)
Downward revision of estimate due to commodity prices	(2,313,890)	(2,303,700)	(3,655,679)	(28,789,545)
Downward revision of estimate due to removal of undeveloped locations	(1,582,060)	(195,410)	(2,061,654)	(2,307,932)
End of year	66,264,286	61,305,027	71,359,014	58,271,882
Proved Developed at beginning of year	41,242,050	34,467,870	19,206,048	32,413,447
Proved Undeveloped at beginning of year	30,116,964	23,804,012	8,603,700	20,352,251
Proved Developed at end of year	38,260,639	34,335,520	41,242,050	34,467,870
Proved Undeveloped at end of year	28,003,648	26,969,507	30,116,964	23,804,012

[1] Oil reserves are stated in barrels; natural gas reserves are stated in thousand cubic feet.

Standardized Measure of Discounted Future Net Cash Flows

December 31,	2020	2019
Future cash flows	$ 2,682,488,655	$ 3,825,773,515
Future production costs	(821,515,126)	(964,887,856)
Future development costs	(244,323,270)	(252,457,833)
Future income taxes	(208,645,934)	(424,715,966)
Future net cash flows	1,408,004,325	2,183,711,860
10% annual discount for estimated timing of cash flows	(852,133,072)	(1,260,536,809)
Standardized Measure of Discounted Future Net Cash Flows	$ 555,871,253	$ 923,175,051

Changes in Standardized Measure of Discounted Future Net Cash Flows

	2020	2019
Beginning of the year	$ 923,175,051	$ 455,944,641
Purchase of minerals in place	—	598,489,190
Improved recovery, less related costs	61,303,074	86,989,301
Extensions and discoveries, less related costs	—	247,652,632
Development costs incurred during the year	29,916,746	152,125,320
Sales of oil and gas produced, net of production costs	(70,634,853)	(137,663,314)
Sales of minerals in place	—	(30,174,528)
Accretion of discount	92,838,323	47,463,292
Net changes in price and production costs	(368,974,767)	(219,608,128)
Net change in estimated future development costs	(3,883,985)	47,617,158
Upward revisions	32,920,723	44,034,636
Revision of previous quantity estimates as a result well performance	(52,731,122)	(64,553,979)
Revision of previous quantity estimates as a result of commodity prices	(26,590,142)	(71,545,320)
Revision of previous quantity estimates as a result removal of uneconomic proved undeveloped locations	(19,812,745)	(34,079,006)
Revision of estimated timing of cash flows	(139,039,115)	(107,443,484)
Net change in income taxes	97,384,365	(92,073,360)
End of the Year	$ 555,871,553	$ 923,175,051

Exhibit 10.16

Execution Version

FOURTH AMENDMENT TO
CREDIT AGREEMENT

THIS FOURTH AMENDMENT TO CREDIT AGREEMENT (hereinafter called this "***Amendment***") is dated as of May [ ], 2017, by and among RING ENERGY INC., a Nevada corporation (the "***Borrower***"), each of the Lenders which is signatory hereto, and SUNTRUST BANK, as Administrative Agent for the Lenders (in such capacity, together with its successors in such capacity "***Administrative Agent***") and as Issuing Bank under the Credit Agreement referred to below.

W I T N E S S E T H:

WHEREAS, the Borrower, Administrative Agent and the Lenders are parties to that certain Credit Agreement dated as of July 1, 2014, as amended by that certain First Amendment to Credit Agreement, dated as of June 26, 2015, that certain Second Amendment to Credit Agreement dated as of July 24, 2015, and that certain Third Amendment to Credit Agreement dated as of May 18, 2016 (as amended by this Amendment and as further amended, modified or restated from time to time, the "***Credit Agreement***"), whereby upon the terms and conditions therein stated the Lenders have agreed to make certain loans to the Borrower upon the terms and conditions set forth therein;

WHEREAS, the Borrower has requested that the Lenders amend the Credit Agreement as set forth below; and

WHEREAS, subject to the terms and conditions hereof, the Lenders are willing to agree to the amendments to the Credit Agreement as set forth herein.

NOW, THEREFORE, for and in consideration of the mutual covenants and agreements herein contained, the parties to this Amendment hereby agree as follows:

SECTION 1. Definitions. Unless otherwise defined in this Amendment, each capitalized term used herein but not otherwise defined herein has the meaning given such term in the Credit Agreement. The interpretive provisions set forth in Sections 1.2, 1.3 and 1.4 of the Credit Agreement shall apply to this Amendment.

SECTION 2. Amendments to Credit Agreement. Effective on the Amendment Effective Date, the Credit Agreement is hereby amended as follows:

(a) ***Section 1.1*** (Definitions) is amended by adding the following new definitions in proper alphabetical order:

"Commitment Reduction Notice" shall have the meaning set forth in Section 2.7(d).

"Reduced Commitment" shall have the meaning set forth in Section 2.7(d).

(b) The definition of "Commitment" in ***Section 1.1*** (Definitions) is amended and restated in its entirety as follows:

"Commitment" shall mean, with respect to each Lender, the commitment of such Lender to make Loans and to acquire participations in Letters of Credit hereunder, expressed as an amount representing the maximum aggregate amount of such Lender's Credit Exposure hereunder. The amount representing each Lender's Commitment shall at any time be the lesser of such Lender's Maximum Loan Amount and such Lender's Pro Rata Share of the then effective

Borrowing Base and shall be reduced pursuant to any Commitment Reduction Notice delivered pursuant to Section 2.7(d).

(c) ***Section 2.7*** of the Credit Agreement is amended by adding the following as a new subsection (d):

"(d) After the receipt of a New Borrowing Base Notice, the Borrower may reduce the Commitments of the Lenders (the "Reduced Commitment"), *provided that* (i) the reduction shall be in an amount that is an integral multiple of $1,000,000 and not less than $5,000,000 and (ii) the Credit Exposures do not exceed the Reduced Commitment. To effectuate a Reduced Commitment, within three (3) Business Days after the Administrative Agent sends the Borrower a New Borrowing Base Notice, the Borrower must submit a written notice to the Administrative Agent of its election to reduce the Commitments (the "Commitment Reduction Notice"). Each Commitment Reduction Notice shall be irrevocable. Each reduction of the Commitments shall be made ratably among the Lenders in accordance with each Lender's Pro Rata Share. Notwithstanding any Commitment Reduction Notice, all relevant determinations under this Agreement based upon the Borrowing Base shall use the Borrowing Base as set forth in the New Borrowing Base Notice until the next Scheduled Redetermination or Interim Redetermination. If the Borrower desires to later reinstate any Commitment reduction set forth in a Commitment Reduction Notice, the Borrower may do so only (1) with the written consent of all Lenders, and (2) after paying to the Lenders Commitment increase fees or upfront fees requested by the Lenders. For the avoidance of doubt, no Reduced Commitment of any Lender shall be increased by any subsequent increase, reaffirmation or reduction of the Borrowing Base (notwithstanding such Lender's approval of such Borrowing Base) unless such Lender expressly consents in writing to such increased Commitment."

SECTION 3. Borrowing Base(a) . Effective on the Amendment Effective Date, the Borrowing Base is increased to $100,000,000 until the next redetermination or adjustment thereof pursuant to the Credit Agreement. The Borrowing Base redetermination provided for by this Amendment is the Scheduled Redetermination for May 1, 2017. This Amendment shall serve as a New Borrowing Base Notice under the Credit Agreement. Pursuant to ***Section 2.7(d)*** of the Credit Agreement, the Borrower desires to reduce the Commitments of the Lenders from $100,000,000 to $60,000,000. The Borrower, Administrative Agent and the Lenders agree that, effective on the Amendment Effective Date, $60,000,000 shall be the Reduced Commitment under the Credit Agreement. This Amendment shall serve as the Commitment Reduction Notice from the Borrower required pursuant to ***Section 2.7(d)*** of the Credit Agreement.

SECTION 4. Conditions of Effectiveness(a) .

(a) This Amendment shall become effective as of the date (the "***Amendment Effective Date***") that each of the following conditions precedent shall have been satisfied:

(1) The Administrative Agent shall have received (which may be by electronic transmission), in form and substance satisfactory to the Administrative Agent, a counterpart of this Amendment which shall have been executed by the Administrative Agent, the Issuing Bank, the Lenders and the Borrower (which may be by PDF transmission);

(2) Each of the representations and warranties set forth in ***Section 5*** of this Amendment shall be true and correct;

(3) Since December 31, 2016, there has been no event or condition that has had or could reasonably be expected to have a Material Adverse Effect; and

(4) Borrower shall have paid all fees and expenses due to the Lenders and the Administrative Agent (including, but not limited to, reasonable attorneys' fees of counsel to the Administrative Agent).

(b) Without limiting the generality of the provisions of Sections 3.1 and 3.2 of the Credit Agreement, for purposes of determining compliance with the conditions specified in ***Section 3(a)***, each Lender that has signed this Amendment (and its permitted successors and assigns) shall be deemed to have consented to, approved or accepted, or to be satisfied with, each document or other matter required hereunder to be consented to or approved by or acceptable or satisfactory to a Lender unless the Administrative Agent shall have received written notice from such Lender prior to the proposed Amendment Effective Date specifying its objection thereto.

(c) The Administrative Agent shall notify the Borrower and the Lenders of the Amendment Effective Date.

SECTION 5. Representations and Warranties. The Borrower represents and warrants to Administrative Agent and the Lenders, with full knowledge that such Persons are relying on the following representations and warranties in executing this Amendment, as follows:

(a) It has the organizational power and authority to execute, deliver and perform this Amendment, and all organizational action on the part of it requisite for the due execution, delivery and performance of this Amendment has been duly and effectively taken.

(b) The Credit Agreement, as amended by this Amendment, the Loan Documents and each and every other document executed and delivered to the Administrative Agent and the Lenders in connection with this Amendment to which it is a party constitute the legal, valid and binding obligations of the Borrower, enforceable against the Borrower in accordance with their respective terms except as enforceability may be limited by applicable bankruptcy, insolvency, or similar laws affecting the enforcement of creditors' rights generally or by equitable principles relating to enforceability.

(c) This Amendment does not and will not violate any provisions of any of the articles or certificate of incorporation, bylaws, and other organizational and governing documents of the Borrower.

(d) No approval, consent, exemption, authorization, or other action by, or notice to, or filing with, any Governmental Authority is necessary or required in connection with the execution, delivery or performance by, or enforcement against, the Borrower of this Amendment.

(e) Before and after giving effect to this Amendment, the representations and warranties of the Borrower contained in *Article IV* of the Credit Agreement or in any other Loan Document are true and correct in all material respects (other than those representations and warranties that are expressly qualified by a Material Adverse Effect or other materiality, in which case such representations and warranties shall be true and correct in all respects).

(f) Before and after giving effect to this Amendment, no Default, Event of Default or Borrowing Base Deficiency exists.

(g) Since December 31, 2016, there has been no event or circumstance which has had or could reasonably be expected to have a Material Adverse Effect.

(h) As of the Amendment Effective Date, notwithstanding any provision in any Collateral Document to the contrary, no Building (as defined in the applicable Flood Insurance Regulation) or Manufactured (Mobile) Home (as defined in the applicable Flood Insurance Regulation) included in the definition of "Mortgaged Property" or "collateral" or similar definition in any Collateral Document and no Building or Manufactured (Mobile) Home is encumbered by any Collateral Document. As used in this paragraph, "Building" means any Building or Manufactured (Mobile) Home, in each case as defined in the applicable Flood Insurance Regulations); and "Flood Insurance Regulations" means (I) the National Flood Insurance Act of 1968 as now or hereafter in effect or any successor statute thereto, (II) the Flood Disaster Protection Act of 1973 as now or hereafter in effect or any successor statute thereto, (III) the National Flood Insurance Reform Act of 1994 (amending 42 USC § 4001, et seq.), as the same may be amended or recodified from time to time, and (IV) the Flood Insurance Reform Act of 2004 and any regulations promulgated thereunder.

SECTION 6. Miscellaneous.

(a) **Reference to the Credit Agreement**. Upon the effectiveness hereof, on and after the date hereof, each reference in the Credit Agreement to "this Agreement," "hereunder," "hereof," "herein," or words of like import, shall mean and be a reference to the Credit Agreement as amended hereby.

(b) **Effect on the Credit Agreement; Ratification**. Except as specifically amended by this Amendment, the Credit Agreement shall remain in full force and effect and is hereby ratified and confirmed. By its acceptance hereof, the Borrower hereby ratifies and confirms each Loan Document to which it is a party in all respects, after giving effect to the amendments set forth herein.

(c) **Extent of Amendments**. Except as otherwise expressly provided herein, the Credit Agreement and the other Loan Documents are not amended, modified or affected by this Amendment. The Borrower hereby ratifies and confirms that (i) except as expressly amended hereby, all of the terms, conditions, covenants, representations, warranties and all other provisions of the Credit Agreement remain in full force and effect, (ii) each of the other Loan Documents are and remain in full force and effect in accordance with their respective terms, and (iii) the Collateral and the Liens on the Collateral securing the Obligations are unimpaired by this Amendment and remain in full force and effect.

(d) **Loan Documents**. The Loan Documents, as such may be amended in accordance herewith, are and remain legal, valid and binding obligations of the parties thereto, enforceable in accordance with their respective terms. This Amendment is a Loan Document.

(e) **Claims**. As additional consideration to the execution, delivery, and performance of this Amendment by the parties hereto and to induce Administrative Agent and Lenders to enter into this Amendment, the Borrower represents and warrants that, as of the date hereof, it does not know of any defenses, counterclaims or rights of setoff to the payment of any Obligations of the Borrower to Administrative Agent, Issuing Bank or any Lender.

(f) **Execution and Counterparts**. This Amendment may be executed in any number of counterparts and by different parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed to be an original and all of which taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of this Amendment by facsimile or pdf shall be equally as effective as delivery of a manually executed counterpart.

(g) **Governing Law**. This Amendment and any claims, controversy, dispute or cause of action (whether in contract or tort or otherwise) based upon, arising out of or relating to this Amendment and the transactions contemplated hereby and thereby shall be construed in accordance with and be governed by the law (without giving effect to the conflict of law principles thereof) of the State of Texas.

(h) **Headings**. Section headings in this Amendment are included herein for convenience and reference only and shall not constitute a part of this Amendment for any other purpose.

SECTION 7. NO ORAL AGREEMENTS. THE RIGHTS AND OBLIGATIONS OF EACH OF THE PARTIES TO THE LOAN DOCUMENTS SHALL BE DETERMINED SOLELY FROM WRITTEN AGREEMENTS, DOCUMENTS, AND INSTRUMENTS, AND ANY PRIOR ORAL AGREEMENTS BETWEEN SUCH PARTIES ARE SUPERSEDED BY AND MERGED INTO SUCH WRITINGS. THIS AMENDMENT AND THE OTHER WRITTEN LOAN DOCUMENTS EXECUTED BY THE BORROWER, ADMINISTRATIVE AGENT, ISSUING BANK AND/OR LENDERS REPRESENT THE FINAL AGREEMENT BETWEEN SUCH PARTIES, AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS BY SUCH PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN SUCH PARTIES.

SECTION 8. No Waiver. The Borrower hereby agrees that no Event of Default and no Default has been waived or remedied by the execution of this Amendment by the Administrative Agent or any Lender. Nothing contained in this Amendment nor any past indulgence by the Administrative Agent, Issuing Bank or any Lender, nor any other action or inaction on behalf of the Administrative Agent, Issuing Bank or any Lender, (i) shall constitute or be deemed to constitute a waiver of any Defaults or Events of Default which may exist under the Credit Agreement or the other Loan Documents, or (ii) shall constitute or be deemed to constitute an election of remedies by the Administrative Agent, Issuing Bank or any Lender, or a waiver of any of the rights or remedies of the Administrative Agent, Issuing Bank or any Lender provided in the Credit Agreement, the other Loan Documents, or otherwise afforded at law or in equity.

Signatures Pages Follow

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered by their proper and duly authorized officers as of the day and year first above written.

RING ENERGY INC.,
as Borrower

By: ______________________________
Name:
Title:

Signature Page to Fourth Amendment to Credit Agreement
Ring Energy, Inc.

SUNTRUST BANK,
as Administrative Agent, as Issuing Bank and as a Lender

By: ______________________________
Name:
Title:

[LENDER],
as a Lender

By: ______________________________
Name:
Title:

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of the name Cawley, Gillespie & Associates, Inc., to the references to us and to our reserves reports for the years ended December 31, 2020, December 31, 2019, and December 31, 2018, in Ring Energy Inc.'s Annual Report on Form 10-K for the year ended December 31, 2020, to references to our report dated February 10, 2021, containing our opinion on estimates of proved reserves, future production and income attributable to certain leasehold interest of Ring Energy, Inc. as of December 31, 2020 (our "Report"), and to the inclusion of our Report as an exhibit in Ring Energy, Inc. 's Annual Report on Form 10-K for the year ended December 31, 2020. We also consent to all such references and to the incorporation by reference of such information and our Report in Ring Energy, Inc.'s Registration Statements on Form S-3 (Nos. 333-215909, 333-229515 and 333-230966) and Form S-8 (No. 333-191485).

Very truly yours,

Cawley, Gillespie & Assoc., Inc.

CAWLEY , GILLESPIE & ASSOCIATES, INC.

Fort Worth, Texas
March 16, 2021

Exhibit 23.2

EideBailly

CPAs & BUSINESS ADVISORS

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference of our report dated March 16, 2021, relating to the financial statements and the effectiveness of internal control over financial reporting of Ring Energy, Inc., which appears in this Form 10-K, together with any other registration statements that permit incorporation by reference.

Eide Bailly LLP

Denver, Colorado
March 16, 2021

Exhibit 31.1

CERTIFICATIONS

I, Paul D. McKinney, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2020, of Ring Energy, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: March 16, 2021

/s/ Paul D. McKinney
Paul D. McKinney, CEO
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, William R. Broaddrick, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2020, of Ring Energy, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: March 16, 2021

/s/ William R. Broaddrick
William R. Broaddrick, CFO
(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 Ring Energy, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2020, as filed with the Securities and Exchange Commission (the “Report”), the undersigned principal executive officer of the Company, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 16, 2021

/s/ Paul D. McKinney
Paul D. McKinney
(Principal 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 Ring Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2020, as filed with the Securities and Exchange Commission (the "Report"), the undersigned principal financial officer of the Company, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 16, 2021

/s/ William R. Broaddrick
William R. Broaddrick
(Principal Financial Officer)

Exhibit 99.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

February 10, 2021

Mr. Alex Dyes
Executive Vice President of Engineering & Corporate Strategy
Ring Energy, Inc.
1725 Hughes Landing Blvd., Suite 900
The Woodlands, TX 77380

Re: Evaluation Summary
Ring Energy, Inc. Interests
Proved Reserves
Texas and New Mexico
As of January 1, 2021

Dear Mr. Dyes:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the above captioned interests as of January 1, 2021. It is our understanding that the proved reserve estimates shown herein constitute 100 percent of all proved reserves owned by Ring Energy, Inc. This report, completed on February 10, 2021, has been prepared for use in filings with the SEC by Ring Energy, Inc. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserves estimates and economic forecasts for the proved reserves are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved
Net Reserves					
Oil/Condensate	-- Mbbl	33,711.1	4,549.5	28,003.6	66,264.3
Gas	-- MMcf	28,365.5	5,970.0	26,969.5	61,305.0
Revenue					
Oil/Condensate	-- M$	1,315,890.7	174,261.1	1,083,391.9	2,573,543.6
Gas	-- M$	50,142.4	7,776.5	51,026.1	108,945.0
Severance and Ad Valorem Taxes	-- M$	101,264.3	11,366.7	77,912.1	190,543.2
Operating Expenses	-- M$	177,043.1	29,604.3	80,961.7	287,609.1
Other Deductions	-- M$	188,051.1	23,490.7	131,841.0	343,382.8
Investments	-- M$	1,278.8	23,880.7	219,163.8	244,323.3
Operating Income (BFIT)	-- M$	898,395.7	93,695.2	624,539.3	1,616,630.3
Discounted @ 10%	-- M$	**397,454.4**	**40,753.7**	**199,899.5**	**638,107.6**

The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

As requested, hydrocarbon pricing of $1.99 per MMBtu of gas (Henry Hub spot) and $36.04 per barrel of oil/condensate (WTI posted) was applied without escalation. In accordance with the Securities and Exchange Commission guidelines, these prices were determined as an unweighted arithmetic average of the first-day-of-the-month price for the previous 12 months. As directed, this 12-month period ends in December 2020. The oil and gas prices were held constant and were adjusted for gravity, heating value, quality, transportation and marketing. The adjusted volume-weighted average product prices over the life of the properties are $38.84 per barrel of oil and $1.78 per Mcf of gas.

Operating costs were based on operating expense records of Ring Energy. Drilling and completion costs were based on estimates provided by Ring Energy and reviewed by Cawley, Gillespie & Associates. Severance tax and ad valorem rates were specified by state/county based on actual rates. As per the Securities and Exchange Commission guidelines, neither expenses nor investments were escalated. The cost of plugging and the salvage value of equipment have not been considered.

The proved reserves classifications conform to criteria of the SEC regulation. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the U.S. Securities and Exchange Commission (SEC) Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the date of this report as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance, volumetric and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserves estimates were based on interpretations of factual data furnished by Ring Energy. Ownership interests were supplied by Ring Energy and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data.

Our work-papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn