United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2022

Or

o **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	**90-0406406**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1725 Hughes Landing Blvd., Suite 900 **The Woodlands, TX**	**77380**
(Address of principal executive offices)	(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 Each Exchange on Which Registered
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 o No x

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

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

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

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

Large accelerated filer	o		Accelerated filer	x
Non-accelerated filer	o	(Do not check if a smaller reporting company)	Smaller reporting company	o
Emerging growth company	o			

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. o

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. x

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

As of June 30, 2022, the aggregate market value of the common voting stock held by non-affiliates of the registrant, based upon the closing stock price on that day on the NYSE American of $2.66 per share, was $281,212,950.

As of March 9, 2023, the registrant had outstanding 180,627,484 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 2023, 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, (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this Annual Report regarding our strategy, future operations, financial position, estimated revenues and expenses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words “may,” “will,” “could,” “would,” “should,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “plan,” “pursue,” “target,” “continue,” “potential,” “guidance,” “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, mechanical failures 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;
- the effects of inflation on our cost structure;
- substantial declines in the estimated values of our proved oil and natural gas reserves;
- our ability to replace our oil and natural gas reserves;
- the effects of rising interest rates on our cost of capital and the actions that central banks around the world undertake to control inflation, including the impacts such actions have on general economic conditions;
- 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;

- the potential for production decline rates and associated production costs for our wells to be greater than we forecast;
- the timing and extent of our success in acquiring, discovering, developing and producing oil and natural gas reserves;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits;
- the possibility that potential divestitures may not occur or could be burdened with unforeseen costs;
- unanticipated reductions in the borrowing base under the credit agreement we are party to;
- our dependence on the availability, use and disposal of water in our drilling, completion and production operations;
- significant competition for oil and natural gas acreage and acquisitions;
- environmental or other governmental regulations, including legislation related to hydraulic fracture stimulation and climate change measures;
- our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- future environmental, social and governance ("ESG") compliance developments and increased attention to such matters which could adversely affect our ability to raise equity and debt capital;
- management's ability to execute our plans to meet our goals;
- 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;
- future cyber risk compliance developments and its effect on the loss of confidentiality, integrity, or availability of information, data, or information (or control) systems that reflect the potential adverse impacts to organizational operations and assets, individuals, or other organizations;
- our ability to find and retain highly skilled personnel and our ability to retain key members of our management team on commercially reasonable terms;
- adverse weather conditions;
- actions or inaction of third-party operators of our properties;
- costs and liabilities associated with environmental, health and safety laws;
- the effect of our oil and natural gas derivative activities;
- social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, including evolving geopolitical and military hostilities in the Middle East, Russia and Ukraine and acts of terrorism or sabotage;

- impacts of world health events, including the coronavirus (“COVID-19”), and any reactive or proactive measures taken by businesses, governments and by other organizations related thereto, and the direct and indirect effects of world health events on the market for and price of oil and natural gas;

- our insurance coverage may not adequately cover all losses that may be sustained in connection with our business activities;

- possible adverse results from litigation and the use of financial resources to defend ourselves;

- and the other factors discussed in Part I, Item 1A-- “Risk Factors” in this Annual Report, as well as in our 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 the Permian Basin of Texas. 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.

As of December 31, 2022, our leasehold acreage positions totaled 124,217 gross (102,175 net) acres and we held interests in 1,056 gross (888 net) producing wells. Proved reserves as of December 31, 2022 were approximately 138.1 million Boe (barrel of oil equivalent), of which we are the operator of approximately 98%. All of our properties are located in the Permian Basin. Our proved reserves are oil-weighted with approximately 64% consisting of oil, 19% consisting of natural gas, and 17% consisting of natural gas liquids. Of those reserves, approximately 65% are classified as proved developed or "PD" and 35% are classified as proved undeveloped, or "PUD." Within the "PD" reserve category, 235 re-completion and re-activation opportunities are classified as proved developed not producing "PDNP" and within the "PUD" reserve category, we have a total of 214 proved locations (43% horizontal and 57% vertical) based on the reserve report as of December 31, 2022.We believe our core leasehold in the Northwest Shelf and Central Basin Platform contain additional potential drilling locations. For the calculation of Boe, a barrel of oil is weighted on a 6 to 1 ratio to one thousand cubic feet ("Mcf") of natural gas.

2022 Highlights and Major Developments

- Amended our revolving credit facility "RBL" with an initial borrowing base of $600.0 million
- Closed the Stronghold Acquisition on August 31, 2022
- Increased liquidity position at year-end 2022 to approximately $188.0 million which was a 205% increase versus year-end 2021 of $61.6 million
- Improved RBL available balance at year-end 2022 to $184.2 million or 31% of undrawn capacity on the RBL versus year-end 2021 of $59.2 million or 17% of undrawn capacity
- Achieved record full year production of 12,364 Boepd (77% Oil), a year-over-year increase of 45%
- Executed a continuous drilling program in 2022 which included drilling 32.00 gross / 31.35 net operated wells consisting of 27.00 gross horizontal wells and 5.00 gross vertical wells
- Increased total Proved Reserves to 138.1 MMBoe at year-end 2022, a year-over-year increase of 78%

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 it believes are vital to the world's health and welfare.

Our Key Principles

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 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 our balance sheet by steadily paying down debt, divesting of non-core assets and becoming a peer leader in Debt/EBITDA metrics.

Our Business Strategy

Our business strategy is guided by the above key principles and implemented by pursuing the following five strategic objectives, which are foundational aspects of our culture and success.

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

Pursue operational excellence with a sense of urgency - We seek to deliver low cost, consistent, timely and efficient execution of our drilling campaigns, work programs and operations. We execute our operations in a safe and environmentally responsible manner, focus on reducing our emissions, apply advanced technologies, and continuously seek ways to reduce our operating cash costs on a per barrel basis.

Invest in high-margin, high rate-of-return projects - We prioritize our work programs and allocate capital to the highest return opportunities in our inventory on an ongoing basis. This objective is key to profitably growing our production and reserve levels and generating the excess cash from operations.

Focus on generating free cash flow and *strengthen our balance sheet* - We seek to continuously reduce long-term debt using excess cash from operations and potentially through the sale of non-core assets. 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 is funded by operational cash flow and limited to balance our production and reserve growth versus paying down debt. We believe that remaining focused and disciplined in this regard will lead to meaningful returns for our shareholders and provide additional financial flexibility to manage potential future swings in business cycles. Our commodity hedges are designed to help ensure the necessary cash flow to adhere to these plans while retaining the flexibility to participate in prevailing commodity markets.

Pursue strategic acquisitions that maintain or reduce our break-even costs - We actively pursue accretive acquisitions, mergers and dispositions in seeking to improve our margins, returns, and break-even costs. 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.

Stronghold Acquisition

On July 1, 2022, Ring and Stronghold Energy II Operating, LLC, a Delaware limited liability company (“Stronghold OpCo”) and Stronghold Energy II Royalties, LP, a Delaware limited partnership (“Stronghold RoyaltyCo”, together with Stronghold OpCo, collectively, “Stronghold”), entered into a purchase and sale agreement (the “Purchase Agreement"), under which Ring acquired (the “Stronghold Acquisition”) interests in oil and gas leases and related property of Stronghold consisting of approximately 37,000 net acres in the Central Basin Platform of the Texas Permian Basin. On August 31, 2022, we completed the Stronghold Acquisition.

Upon closing of the Stronghold Acquisition, Stronghold exercised its right to designate two directors to our Board of Directors (the "Board"). On September 1, 2022, Roy I. Ben-Dor and David S. Habachy were appointed to the Board.

Primary Business Operations

We seek to rigorously manage our asset portfolio to optimize shareholder value over the long term.

In the first quarter of 2022, we contracted a rig for our horizontal drilling program and began operations on January 31st. We drilled and completed three 1-mile horizontal wells and one 1.5-mile horizontal well in the Central Basin Platform. We then moved the rig to the Northwest Shelf and drilled two 1-mile horizontal wells. All wells drilled in the first quarter had a working interest of 100%.

In the second quarter of 2022, we drilled a total of nine wells, completed seven wells, and began the completion process on four wells, all in the Northwest Shelf. The first wells completed were the two 1-mile horizontal wells, which were drilled in the first quarter. Next, we drilled and completed two 1-mile horizontal wells with a working interest of 100%, two 1.5-mile horizontal wells with a working interest of approximately 98.7% and one 1-mile horizontal well with a working interest of approximately 75.4%. We also drilled and began the completion process on an additional four 1-mile horizontal wells. Two of the wells have a working interest of 100%, one has a working interest of approximately 87.9%, and the fourth has a working interest of 75%.

In the third quarter of 2022, we completed and placed on production the four aforementioned 1-mile horizontal wells in the Northwest Shelf, which were drilled in the second quarter. Next, we drilled and completed two 1.5-mile horizontal wells and one 1-mile horizontal well in the Central Basin Platform and two 1-mile horizontal wells in the Northwest Shelf, each with a working interest of 100%. During the last month of the quarter, we drilled and began the completion process on three 1-mile horizontal wells in the Northwest Shelf, two with a working interest of 99.7% and one with a working interest of 100%. In total, during the third quarter of 2022, we drilled eight, completed nine, and began the completion process on three horizontal wells. With the addition of the Stronghold Acquisition assets in the Central Basin Platform, we also performed three vertical well re-completions.

In the fourth quarter of 2022, we completed and placed on production the three aforementioned 1-mile horizontal wells in the Northwest Shelf. Next, we drilled and completed two 1-mile horizontal wells with a working interest of 100%, also in the Northwest Shelf. To complete the 2022 horizontal drilling program, we drilled and completed two 1.5-mile horizontal wells in the Central Basin Platform. In addition to the horizontal wells, we performed nine more vertical well re-completions and drilled and completed five new vertical wells on the Stronghold Acquisition assets located in Crane County, Texas, of the Central Basin Platform, all with a working interest of 100%.

In summary, for 2022, we drilled and completed 27 horizontal wells and 5 vertical wells, along with 12 vertical well re-completions on the Stronghold Acquisition assets. The table below sets forth our drilling and completion activities for 2022 by quarter through December 31, 2022.

Quarter	Area	Wells Drilled	Wells Completed	Recompletion
1Q 2022	Central Basin Platform (Horizontal)	4	4	
	Central Basin Platform (Vertical)	—	—	
	Northwest Shelf	2	—	
2Q 2022	Central Basin Platform (Horizontal)	—	—	
	Central Basin Platform (Vertical)	—	—	
	Northwest Shelf	9	7	
3Q 2022	Central Basin Platform (Horizontal)	3	3	
	Central Basin Platform (Vertical)	—	—	
	Northwest Shelf	5	6	
4Q 2022	Central Basin Platform (Horizontal)	2	2	
	Central Basin Platform (Vertical)	5	5	
	Northwest Shelf	2	5	

Ring Energy's Strengths

Our strengths include:

- high quality asset base in one of North America's leading oil and gas producing regions characterized by relatively 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 with substantive technical and operational expertise;
- operating control over most of our production and development activities; and
- 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 competent 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. In addition, 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 this highly competitive environment.

Marketing, Pricing, and Transportation

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 in our areas of operation. 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.

Our oil is transported from the wellhead to tank batteries or delivery points through our flow-lines or gathering systems. Purchasers of our oil take delivery (i) at a pipeline delivery point or (ii) at our tank batteries for transport by truck. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering systems. We have implemented a Leak Detection and Repair program, or LDAR, to locate and repair leaking components including valves, pumps and connectors in order to minimize the emission of fugitive volatile organic compounds and hazardous air pollutants. In addition, we install vapor recovery units in our newly installed tank batteries which also reduces emissions. Our produced salt water is generally moved by pipeline connected to our operated salt water disposal wells or by pipeline to commercial disposal facilities.

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 year ended December 31, 2022, sales to three customers, Phillips 66 Company ("Phillips"), NGL Crude Partners ("NGL Crude"), and Enterprise Crude Oil LLC ("Enterprise") represented 68%, 13% and 5%, respectively, of our oil, natural gas, and natural gas liquids revenues. As of December 31, 2022, Phillips represented 69% of our accounts receivable, NGL Crude represented 7% of our accounts receivable and Enterprise represented 10% 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, 2022, we were not committed to providing a fixed quantity of oil or natural gas under any existing contracts.

Commodity Hedging

We have an active commodity hedging program through which we seek to hedge a meaningful portion of our expected oil and gas production, reducing our exposure to downside commodity prices and enabling us to protect cash flows to meet our debt obligations under our credit facility and maintain liquidity to fund our capital expenditures needs.

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, in January 2021, President Biden signed an Executive Order directing the Department of Interior (the "DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed, although litigation over the leasing pause remains ongoing. In February 2022, another judge ruled that the Biden Administration's efforts to raise the cost of climate change in its environmental assessments, would increase energy costs and damage state revenues from energy production. This ruling has caused federal agencies to delay issuing new oil and gas leases and permits on federal lands and waters. While we do not have a significant federal lands acreage position (240 net acres as of December 31, 2022), these actions could have a material adverse effect on our industry and the Company.

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, ("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 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") 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 ("OPA"); 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 ("SDWA"). 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 natural 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 hazardous and solid (non-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 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 material 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 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. In 2012 and 2016, the EPA issued New Source Performance Standards to regulate emissions of sources of volatile organic compounds (“VOCs”), sulfur dioxide, air toxics and methane from various oil and natural gas exploration, production, processing and transportation facilities. On May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified, and existing oil and gas facilities. Given the long-term trend toward increasing regulation, future federal Greenhouse Gas (“GHG”) regulations of the oil and gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities. In November 2021, the EPA proposed new source performance standards and emissions guidelines to reduce methane and other pollution from new and existing sources in the oil and gas industry. The proposed rule would include, among other things, a comprehensive monitoring program for new and existing well sites, zero-emissions standards for new and existing pneumatic controls, and standards to eliminate venting of associated gas and requirements for the capture and sale of natural gas where a sales line is available. If adopted, these requirements could increase our costs to operate and control pollution. In November 2022, the EPA issued a Supplemental Proposal regarding the proposed new source performance standards and emissions guidelines for reducing methane and VOCs in the oil and natural gas sector. The Supplemental Proposal expands the November 2021 proposal to include more comprehensive requirements to reduce emissions, including application of methane monitoring obligations to wellhead-only sites and well sites with low emissions. It also would create a new third-party monitoring program to flag large emissions events known as the "Super-Emitter Response Program." The EPA expects to finalize its new methane rules in 2023. The foregoing laws, regulations, and standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. Until these rules are formally adopted, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 ("IRA"). The IRA allocated $1.55 billion to the Methane Emissions and Waste Reduction Incentive Program. The IRA also required the EPA to implement a waste emission charge on methane emitted from applicable oil and gas facilities that exceed certain thresholds. The methane charge goes into effect in 2024 at $900 per metric ton of methane and increases to $1,500 per metric ton of methane by 2026. The charge will act as an incentive for operators to reduce emissions by minimizing leaks and replacing equipment rather than paying for excessive emissions.

In November 2022, the Department of the Interior announced a proposed rule from the Bureau of Land Management ("BLM") that would impose additional requirements on oil and natural gas production on federal and Tribal lands, including the use of "low bleed" pneumatic equipment and vapor recovery for oil storage tanks, implementation of leak detection plans, implementation of waste minimization plans, and monthly limits on royalty-free flaring. If adopted, these rules could affect our adversely affect our production of oil and gas pursuant to federal leases in New Mexico.

In October 2015, the EPA announced that it was lowering the primary National Ambient Air Quality Standards ("NAAQS") for ozone from 75 parts per billion to 70 parts per billion. Since that time, the EPA has issued area designations with respect to ground-level ozone. In December 2020, the EPA announced its intention to leave the ozone NAAQS unchanged at 70 parts per billion rather than lower them further. However, as discussed above, that action could be subject to reversal following the Biden Administration's January 2021 executive order. In mid-2022, the Biden Administration announced that it was considering designating the Permian Basin in Texas as a "non-attainment zone," which, if designated, would result in increased permitting and compliance requirements for drilling operations in the state to decrease ozone levels. The Biden Administration has since omitted the potential designation from an agenda of planned regulations, indicating that it is not expected to be finalized in the next year. The EPA, however, could revive the effort in the future. In 2022, the New Mexico Environment Department ("NMED") adopted "ozone precursor rules." The ozone precursor rules went into effect on August 5, 2022 and apply to oil and gas sources in New Mexico that would cause or contribute to ambient ozone concentrations that exceed 95% of the NAAQs for ozone. As of the effective date, these rules apply to oil and natural gas production in the following counties in New Mexico: Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia. The rules apply to certain crude oil and natural gas production and processing equipment associated with operations. Reclassification of areas of state implementation of NAAQS, or designation of areas in which we operate as non-attainment zones, could result in stricter permitting requirements, delay, or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Moreover, the NMOCD recently adopted new rules, which require oil and gas operators to capture 98 percent of their methane waste by the end of 2026. The new rules went into effect on May 25, 2021. While the State of Texas has not formally conducted a recent rulemaking related to air emissions, scrutiny of oil and natural gas operations and the rules affecting them have increased in recent years. For example, the EPA and environmental non-governmental organizations have conducted flyovers with optical gas imaging cameras to survey emissions from oil and natural gas production facilities and transmission infrastructure. In August 2022, for example, the EPA announced that it would be conducting helicopter flyovers of the Permian Basin region in New Mexico and Texas. The flyovers used infrared cameras to survey oil and gas operations to identify large emitters of methane and VOCs. Based on data obtained during flyovers, EPA intends to initiate enforcement follow up actions with facilities operators. In addition, the RRC has increased oversight related to flaring, with reporting reviews and site inspections. While none of these activities increases our compliance obligations, they signal the potential for increased enforcement and possible rulemaking in the future.

Oil Pollution Prevention

The OPA 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 OPA. 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.

In January2023, the EPA and the Corps issued a final rule that revises the definition of WOTUS. The final rule has been challenged by several states and industry groups. As a result of these developments, the scope of federal jurisdiction under the CWA is uncertain at this time. 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 SDWA, 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 SDWA 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.

In New Mexico, the New Mexico Oil Conservation Division ("NMOCD") administers the UIC program for all injection wells that are related to oil and natural gas production. In Texas, the Texas Railroad Commission ("RRC") regulates the disposal of produced water by injection well. Permits must be obtained before drilling saltwater disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related waste waters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or placed volumetric injection limits on existing wells or imposed moratoria on the use of such injection wells. In response to concerns related to induced seismicity, regulators in some states have already adopted or are considering additional requirements related to seismic safety. For example, the RRC has adopted rules for injection wells to address these seismic activity concerns in Texas. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. In 2021, the NMOCD announced a new plan for responding to increased seismic activity in the Permian Basin. Under the new plan, pending permits for wastewater injection in certain areas will be subject to additional reporting and monitoring requirements. More stringent regulation of injection wells could lead to reduced construction or the capacity of such wells, which could in turn impact the availability of injection wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. The costs associated with the disposal of proposed water are commonly incurred by all oil and natural gas producers, however, and we do not believe that these costs will have a material adverse effect on our operations. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

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. 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 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.

Additionally, New Mexico has adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. 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 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.

Additionally, 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. At the international level, there is an agreement, the United Nations-sponsored "Paris Agreement," for nations to limit their GHG emissions through non-binding, individually determined reduction goals every five years after 2020. The United States rejoined the Paris Agreement in February 2021. In early 2021, the Biden Administration issued a moratorium on oil and gas leasing on federal lands and waters to reduce emissions. Since then, the moratorium has been the subject of litigation and, in August 2022, a federal judge entered an injunction against the moratorium. In November 2021, the United States participated in the United Nations Climate Change Conference in Glasgow, Scotland, United Kingdom (“COP26”). COP26 resulted in a pact among approximately 200 countries, including the United States, called the Glasgow Climate Pact. Relatedly, the United States and European Union jointly announced the launch of the “Global Methane Pledge,” which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including “all feasible reductions” in the energy sector. In conjunction with COP26, the United States committed to an economy-wide target of reducing net greenhouse gas emissions by 50-52 percent below 2005 levels by 2030. Also in November 2021, President Biden signed a $1 trillion dollar infrastructure bill into law. The new infrastructure law includes several climate-focused investments, including upgrades to power grids to accommodate increased use of renewable energy and expansion of electric vehicle infrastructure. The above-referenced IRA allocated $369 billion to energy and climate initiatives. In November 2022, the United States participated in the United Nations Climate Change Conference in Egypt (“COP27”). 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. Although it is not possible at this time to predict what additional domestic legislation may be adopted in light of the Paris Agreement or the Glasgow Climate Pact, or how legislation or new regulations that may be adopted based on the Paris Agreement or the Glasgow Climate Pact to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, limiting emissions of GHGs from, our equipment and operations, or restricting federal leases could impair our production, could require us to incur costs to reduce emissions of GHGs associated with our operations and could decrease demand for oil and natural gas.

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. We also are aware that the SEC intends to propose new and additional rules regarding company disclosure of climate change risk. We will monitor and comply with any such promulgated rules.

Threatened and endangered species, migratory birds and natural resources

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act ("ESA"), the Migratory Bird Treaty Act ("MBTA") and the Clean Water Act. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. As a result of a 2011 settlement agreement, the FWS was required to determine whether to identify more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The FWS missed the deadline but reportedly continues to review new species for protected status under the ESA pursuant to the settlement agreement. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result. Similar protections are offered to migratory birds under the MBTA. Recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds, we believe that we are in substantial compliance with the ESA and the MBTA, and we are not aware of any proposed ESA listings that will materially affect our operations. Nevertheless, we are monitoring listings and proposed listings by the FWS to ensure continued compliance. In November 2022, FWS listed the southern distinct population segments of the lesser prairie-chicken that occupy habitats in eastern New Mexico and the southwest Texas Panhandle. In January 2023, FWS listed the Sacramento Mountains checkerspot butterfly in New Mexico. The federal government in the past has issued indictments under the MBTA to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. In January 2020, a new DOI rule went into effect clarifying that only the intentional taking of protected migratory birds is subject to prosecution under the MBTA. In December 2021, however, that rule was revoked, and a new rule took effect reinstating the prohibition on incidental takes under the MBTA. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce our oil and natural gas reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

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 highly trained people who exemplify our core values of honesty and integrity, and are diligent, hard-working individuals who deliver results, and who are good neighbors that contribute to the communities in which they live.

As of December 31, 2022, we had 98 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 24% are women and approximately 49% 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 our 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 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 are 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; and
- providing additional paid sick leave for quarantined employees.

Seasonal Nature of Business

Weather conditions often affect the demand for, and prices of, natural gas and can also delay oil and natural gas drilling, completion and production activities, disrupting our overall business plans. Generally, the demand for oil and natural gas fluctuates depending on the time of year. Seasonal anomalies such as mild winters and summers may sometimes lessen this fluctuation. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. 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. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Available Information

Our 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 will be available through our 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 a 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

Our business is subject to various risks and uncertainties in the ordinary course of business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition, or results of operations. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. Readers should carefully consider the risk factors included below as well as those matters referenced in this Report under “Forward-Looking Statements” and other information included and incorporated by reference into this Report.

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 as compared to vertical drilling.

Our operations use 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 vertical wells;
- landing our wellbores in the desired drilling zones;
- staying in the desired drilling zones while drilling horizontally through the formations;
- running our casing the entire length of wellbores; and
- being able to run tools and other equipment consistently through horizontal wellbores.

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 and other equipment 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:

- unforeseen title issues;
- 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 of wells; and
- potential environmental and other liabilities.

Our assessments 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 generally 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 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.

Because a substantial percentage of our proved properties are proved undeveloped (approximately 35%), 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.

While our current business plan is to generally 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 have entered into crude oil and natural gas price hedging arrangements with respect to a significant 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 significant portion of our production. In addition, these derivative contracts typically limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. As part of our hedging strategy, we have in place derivative contracts covering percentages of our future estimated production in accordance with our Credit Agreement.

Hedging transactions may expose us to risk of financial loss.

While intended to reduce the effects of volatile oil and natural gas prices, derivative contracts designed as hedges 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.

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

Natural disasters, adverse weather conditions (particularly abnormally cold weather and thunderstorms), floods, pandemics, 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 disruptions, any of which could have an adverse effect on our business, operating results, and financial condition.

The coronavirus outbreak 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 other pandemics occur, they could have a material adverse impact on our business operations, operating results and financial condition.

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 management team and workforce. Failure to ensure that the Company has the depth and breadth of management and personnel with the necessary skill sets and experience could impede its ability to achieve 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 packages in our industry, as well as inflation pressures, 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;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the actions of oil exporting countries that are not members of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- acts of war and related armed conflicts;

- 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. 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 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, in January 2021, President Biden signed an Executive Order directing the Department of Interior (the "DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed, although litigation over the leasing pause remains ongoing. In February 2022, another judge ruled that the Biden Administration's efforts to raise the cost of climate change in its environmental assessments, would increase energy costs and damage state revenues from energy production. This ruling has cause federal agencies to delay issuing new oil and gas leases and permits on federal lands and waters. While we do not have a significant federal lands acreage position (240 net acres as of December 31, 2022), these actions could have a material adverse effect on our industry, the public perception of oil and gas companies such as ours and the willingness of the public and financial institutions to provide capital for 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 well or project uneconomical. Further, many factors may curtail, delay or cancel drilling, including 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 financial carrying values of our oil and natural gas properties which could negatively impact the trading value of our common stock.

Accounting rules require that we review periodically the financial 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 financial carrying value of our oil and natural gas properties. A write-down would likely constitute a non-cash charge to earnings. The cumulative effect of a write-down could also negatively impact the trading price of our common stock.

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 years ended December 31, 2022, and 2021, we did not incur any write-downs. During the year ended December 31, 2020, we recorded a non-cash write-down of $277.5 million. 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 financial carrying value of such assets and an equivalent charge to earnings.

It is difficult to predict with reasonable certainty the amount of any 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 bank borrowing base, potentially requiring earlier than anticipated debt repayment, which could negatively impact our financial position, results of operations and the trading value of our common stock.

Decreases in oil and natural gas prices could result in reductions in the borrowing base under our Credit Facility, thus requiring earlier than anticipated repayment of debt or trigger a possible default under our Credit Facility in the event we are unable to make payments or repayments under the Credit Facility on a timely basis.

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 calculated 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 certain 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 common stock. 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 and 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 exploration and development, 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 producing our current reserves and economically finding or acquiring additional recoverable reserves. If we are unable to develop, 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.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that we or they own.

Many of our properties are in reservoirs that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations by us or other operators could cause depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells by us or other operators could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production from a given pad, which may cause volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

Extreme weather conditions, which could become more frequent or severe due to multiple factors, could adversely affect our ability to conduct drilling, completion and production activities in the areas where we operate.

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

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

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

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas and NGLs, which could have an adverse effect on our business, financial condition and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes in certain areas to underground injection, which has led to greater public scrutiny of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

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. There is ongoing controversy regarding the leasing of federal lands. For example, 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.

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil and natural gas exploration and production activities, and reduce demand for the oil and natural gas we produce.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, President Biden has highlighted addressing climate change as a priority of his administration, which includes certain potential initiatives for climate change legislation to be proposed and passed into law. Moreover, federal regulators, state and local governments, and private parties have taken (or announced that they plan to take) actions that have or may have a significant influence on our operations. For example, in response to findings that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA for those emissions. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations.

The federal regulation of methane from oil and gas facilities has been subject to substantial uncertainty in recent years. In June 2016, the EPA finalized NSPS, known as Subpart OOOOa, that establish emission standards for methane and VOCs from new and modified oil and natural gas production and natural gas processing and transmission facilities. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified and existing oil and gas facilities. Subsequently, the U.S. Congress approved, and President Biden has signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. In response to President Biden's executive order, in November 2021, the EPA issued a proposed rule that, if finalized, would establish Quad Ob as new source and Quad Oc as first-time existing source standards of performance for methane and VOC emissions for the crude oil and natural gas source category. Owners or operators of affected emission units or processes would have to comply with specific standards of performance that may include leak detecting using optical gas imaging and subsequent repair requirements, reduction of regulated emissions through capture and control systems, zero-emission requirements for certain equipment or processes and operations and maintenance requirements. In November 2022, the EPA published a supplemental proposal, which, among other items, would impose expanded inspection, monitoring and emissions control requirement on oil and gas sites, as well as strengthen requirements related to emissions from equipment and routine flaring. The proposal would also establish a "Super Emitter Response Program" that would require operator response to emissions events exceeding 200 pounds per hour, as detected by regulatory authorities or qualified third-parties. The proposal is currently subject to public comment and is expected to be finalized in 2023. Separately, certain provisions of the IRA 2022 address methane regulation by imposing the first federal fee on excess methane emissions. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility.

Internationally, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again at COP26, during which multiple announcements were made, including a call for parties to eliminate certain oil and natural gas subsidies and pursue further action on non-CO2 GHGs. These goals were reaffirmed at COP27 in November 2022. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26 or other international conventions cannot be predicted at this time. Concern over the threat of climate change has also resulted in increasing political risks in the United States, including climate-change related pledges made by President Biden and other public office representatives. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the oil and natural gas industry and increased emphasis on climate-related risks across agencies and economic sectors. Additionally, in November 2021, the Biden Administration released “The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050,” which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO2 GHG emissions, such as methane and nitrous oxide.

Increasingly, oil and natural gas companies are exposed to litigation risks associated with the threat of climate change. A number of parties have brought lawsuits against oil and natural gas companies in state or federal court for alleged contributions to, or failures to disclose the impacts of, climate change. We are not currently party to any such litigation, but could be named in future actions making similar claims of liability. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Additionally, in response to concerns related to climate change, companies in the oil and natural gas industry may be exposed to increasing financial risks. Financial institutions, including investment advisors and certain sovereign wealth, pension and endowment funds, may elect in the future to shift some or all of their investments into non-oil and natural gas related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices, and some of them may elect in the future not to provide funding for oil and natural gas companies. Many of the largest U.S. banks have made net zero commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps quantify and reduce those emissions. In addition, at COP26, the Glasgow Financial Alliance for Net Zero (“GFANZ”) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing and/or underwriting activities to net zero emissions by 2050. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the oil and natural gas industry. For example, the Federal Reserve has joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector and, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. A material reduction in the capital available to the oil and natural gas industry could make it more difficult to secure funding for exploration, development, production, transportation and processing activities, which could result in decreased demand for our products or otherwise adversely impact our financial performance.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives related to climate change or GHG emissions from oil and natural gas facilities could result in increased costs of compliance or costs of consumption, thereby reducing demand for, oil and natural gas. Additionally, political, litigation, and financial risks may result in (i) restriction or cancellation of certain oil and natural gas production activities, (ii) incurrence of obligations for alleged damages resulting from climate change, or (iii) impairment of our ability to continue operating in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

Moreover, climate change may also result in various physical risks such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns, that could adversely impact our financial condition and operations, as well as those of our suppliers or customers. Such physical risks may result in damage to our facilities, or otherwise adversely impact our operations, such as if we become subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact the infrastructure on which we rely to produce or transport our products. One of more of these developments could have a material adverse effect on our business, financial condition and operations. In addition, while our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

Changes in tax laws or the interpretation thereof or the imposition of new or increased taxes or fees may adversely affect our operations and cash flows.

From time to time, federal and state level legislation has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key federal and state income tax provisions currently available to oil and natural gas exploration and development companies. Such legislative changes have included, but have not been limited to, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies and (v) an increase in the federal income tax rate applicable to corporations such as us. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on oil and natural gas extraction. The passage of any legislation as a result of these proposals and other similar changes in federal income tax laws or the imposition of new or increased taxes or fees on oil and natural gas extraction could adversely affect our operations and cash flows.

In addition, on August 16, 2022, President Biden signed into law the IRA, which includes, among other things, a corporate alternative minimum tax (the "CAMT"), provides for an investment tax credit for qualified biomass property and introduces a one percent excise tax on corporate stock repurchases after December 31, 2022. Under the CAMT, a 15 percent minimum tax will be imposed on certain adjusted financial statement income of "applicable corporations," which is effective beginning January 1, 2023. The CAMT generally treats a corporation as an applicable corporation in any taxable year in which the "average annual adjusted financial statement income" of the corporation and certain of its subsidiaries and affiliates for a three-taxable-year period ending prior to such taxable year exceeds $1 billion. We are currently assessing the potential impact of these legislative changes and will continue to evaluate the overall impact of other current, future and proposed regulations and interpretive guidance from tax authorities on our effective tax rate and consolidated balance sheets. We are unable to predict whether any such changes or other proposals will ultimately be enacted.

New climate disclosure rules proposed by the SEC may increase our costs of compliance and adversely impact our business.

On March 21, 2022, the SEC proposed new rules relating to the disclosure of a range of climate-related risks. We are currently assessing the proposed rule, but at this time we cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. According to the SEC’s Fall 2022 regulatory agenda, the proposed climate disclosure rule is scheduled to be finalized in April 2023. To the extent this rule is finalized as proposed, we could incur increased costs relating to the assessment and disclosure of climate-related risks, including increased legal, accounting and financial compliance costs, as well as making some activities more difficult, time-consuming and costly, and placing strain on our personnel, systems and resources. We may also face increased litigation risks related to disclosures made pursuant to the rule if finalized as proposed. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors. The SEC proposes certain phase-in compliance dates for disclosures under the proposed rules, including for GHG emissions metrics.

Risks Relating to Our Capital Structure

We have significant indebtedness.

We have a Credit Facility in place with $600.0 million in commitments from borrowings and letters of credit under our Second Amended and Restated Credit Agreement dated August 31, 2022 with Truist Bank as Administrative Agent ("Credit Agreement"). As of December 31, 2022, $415.0 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;
- we are required to put into place derivative contracts to hedge a significant portion of our oil and gas production;
- 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. Further, our borrowings under our Credit Facility expose us to interest rate risks, as it bears variable interest based upon a prime rate and is therefore susceptible to interest rate fluctuations.

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, historically 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.

We continue to be impacted by inflationary pressures on our operating costs and capital expenditures.

Beginning in the second half of 2021 and continuing throughout 2022, we, similar to other companies in our industry, experienced inflationary pressures on our operating costs and capital expenditures - namely the costs of fuel, steel (i.e., wellbore tubulars), labor and drilling and completion services. Such inflationary pressures on our operating and capital costs, which we currently expect to continue in 2023, have impacted our cash flows and results of operations. We have undertaken, and plan to continue with, certain initiatives and actions (such as agreements with service providers to secure the costs and availability of services) to mitigate such inflationary pressures. However, there can be no assurance that such efforts will offset, largely or at all, the impacts of any future inflationary pressures on our operating costs and capital expenditures and, in turn, our cash flows and results of operations.

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 process and record financial and operating data, estimate quantities of oil and natural gas reserves, 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

We have recently registered 63,888,878 shares of our common stock for possible resale by certain of our stockholders and have exercisable warrants for 14,590,366 shares of common stock, resulting in significant "market overhang" of our common stock.

In connection with the recently completed Stronghold Acquisition, we registered 63,888,878 shares of our common stock with the SEC for possible resale by Stronghold stockholders. This represents approximately 35% of our presently outstanding shares of common stock and if the selling stockholders choose to sell all or a large number of their shares, from time to time, it likely would have a depressive effect on the market price of our common stock. In addition, we have outstanding warrants with respect to 14,590,366 shares of common stock with an exercise price of $0.80 per share that have been registered for resale. The holders could choose to sell the shares of common stock acquired upon exercise of their warrants, which could also have a depressive effect on the market price of 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 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 currently do not pay cash dividends on our common stock.

We currently intend to retain future earnings, if any, to 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, the terms of our Credit Agreement have restrictions on dividend payments to our equity holders, including our common stockholders.

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 typically 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 engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas.

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 developing our existing oil and natural gas properties and pursuing strategic acquisitions of additional properties.

Developing Existing Properties

We believe that there is significant value to be created by drilling the undeveloped opportunities on our properties. As of December 31, 2022, we owned interests in a total of 101,773 gross (87,326 net) developed acres and operate the vast majority of our acreage position. In addition, as of December 31, 2022, we owned interests in approximately 22,444 gross (14,849 net) undeveloped acres. While our near-term plans are focused on 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 that can earn attractive rates of return on capital employed. Within the Northwest Shelf, we have a total of 73 proved undeveloped locations (85% horizontal and 15% vertical) and 19 PDNP opportunities based on the reserve report as of December 31, 2022. Our reserve estimates account for the capital costs required to develop these wells. We believe the Northwest Shelf leases contain additional potential drilling locations. Within the Central Basin Platform, we have a total of 141 proved undeveloped locations (21% horizontal and 79% vertical) and 205 PDNP opportunities based on the reserve report as of December 31, 2022. Our reserve estimates account for the capital costs required to develop these wells. We believe the Central Basin Platform leases contain additional potential drilling locations.

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 an experienced team of management, engineering, geoscience, and land 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

The Company's significant operations are in two core areas which it has actively drilled over the last several years located in the Northwest Shelf and the Central Basin Platform of the Permian Basin.

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, 2022, we owned interests in a total of 18,270 gross (13,930 net) developed acres and 18,539 gross (12,512 net) undeveloped acres. As of December 31, 2022, the Company had interests in approximately 27 gross vertical and 139 horizontal producing wells, of which we operate 27 vertical and 108 horizontal wells. The horizontal wells predominately produce from the San Andres conventional reservoir and the verticals produce from Wolfcamp and Devonian reservoirs.

Central Basin Platform - Andrews, Gaines, Crane, Winkler, and Ward Counties, Texas leases – In 2011, we acquired a 100% working interest and a 75% net revenue interest in our 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. In 2022, we acquired properties consisting of approximately 37,000 net acres, with an average working interest of 99% and an average net revenue interest of 88% for oil and 96% for natural gas in our initial leases in Crane, Winkler, and Ward counties. As of December 31, 2022, we owned interests in a total of 64,774 gross (54,959 net) developed acres and 3,905 gross (2,337 net) undeveloped acres. As of December 31, 2022, the Company had interests in approximately 625 gross vertical and 195 horizontal producing wells, of which we operate 518 vertical and 193 horizontal wells. The horizontal wells predominately produce from the San Andres conventional reservoir and the verticals produce from a variety of conventional pay sands including Holt, Glorieta, Clear Fork, Wichita Albany, Tubb, Wolfcamp and Devonian reservoirs.

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 lending 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, 2022, our estimated proved reserves had a pre-tax PV-10 value (present value discounted at 10%) of approximately $2,773.7 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $2,272.1 million, 100% of which relates to our properties in the Permian Basin in Texas and New Mexico. We spent approximately $360.1 million on acquisitions and capital projects during 2022 and 2021. We expect to further develop these properties through additional drilling.

The following table summarizes our total net proved reserves, pre-tax PV-10 value and Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2022. All of our reserves are in the Permian Basin in Texas and New Mexico.

Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Liquids (Bbl)	Total (Boe) [1]	Pre-Tax PV-10 Value [2]	Standardized Measure of Discounted Future Net Cash Flows
88,704,743	157,870,449	23,105,658	138,122,143	$ 2,773,656,500	$ 2,272,113,518

(1) Six Mcf is deemed the equivalent of one Boe.
(2) PV-10 is a non-GAAP financial measure. See below for a reconciliation.

We present the pre-tax PV-10 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 Report when comparing our asset base and performance to other comparable oil and natural gas exploration and production companies. PV-10 is a non-GAAP measure that differs from a measure under accounting principles generally accepted in the United States ("GAAP") known as "standardized measure of discounted future net cash flows" in that PV-10 is calculated without including future income taxes. PV-10 does not necessarily represent the fair market value of oil and natural gas properties. PV-10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

The table below provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows (*in thousands*):

Present value of estimated future net revenues (PV-10)	$	2,773,657
Future income taxes, discounted at 10%	$	501,543
Standardized measure of discounted future net cash flows	$	2,272,114

Reserve Quantity Information

Our estimates of proved reserves and related valuations are based on reports independently determined and prepared by Cawley, Gillespie & Associates, Inc. ("CGA"), 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, natural gas and natural gas liquid reserves is shown below.

	Oil (Bbl)	Gas (Mcf)	Natural Gas Liquids (Bbl)[2]	Boe[1]
Balance, December 31, 2020	66,264,286	61,305,027	—	76,481,791
Purchase of minerals in place	2,180,497	824,512	—	2,317,916
Extensions, discoveries and improved recovery	3,975,675	5,172,392	—	4,837,740
Sales of minerals in place	(462,970)	(555,879)	—	(555,617)
Production	(2,686,940)	(2,535,188)	—	(3,109,471)
Revisions of previous quantity estimates	(3,431,939)	7,562,925	—	(2,171,452)
Balance, December 31, 2021	65,838,609	71,773,789	—	77,800,907
Purchase of minerals in place	28,086,920	108,456,107	16,715,626	62,878,564
Extensions, discoveries and improved recovery	628,978	522,178	52,810	768,818
Production	(3,459,477)	(4,088,642)	(371,337)	(4,512,254)
Revisions of previous quantity estimates	(2,390,287)	(18,792,983)	6,708,559	1,186,108
Balance, December 31, 2022	88,704,743	157,870,449	23,105,658	138,122,143

(1) Six Mcf is deemed the equivalent of one Boe.
(2) At year-end 2022, we began reporting reserves on a three-stream basis, including natural gas liquids separately from natural gas.

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During the year ended December 31, 2022, our extensions and discoveries of 769 MBoe (one thousand Boe) resulted primarily from the 2022 operated drilling program in the Northwest Shelf and Central Basin Platform as well as non-operated activity in the Northwest Shelf. Revisions of 1,186 MBoe were predominately the result of converting from two-stream to three-stream reserves, the removal of proved undeveloped reserves in our Delaware asset, well performance, increased cost from 2022 industry activity, and increased commodity pricing.

Our proved oil, natural gas and natural gas liquid reserves are shown below.

	For the years ended December 31,	
	2022	2021
Oil (Bbl)		
Developed	57,012,137	36,820,824
Undeveloped	31,692,606	29,017,785
Total	88,704,743	65,838,609
Natural Gas (Mcf)		
Developed	106,399,050	39,748,880
Undeveloped	51,471,399	32,024,909
Total	157,870,449	71,773,789
Natural Gas Liquids (Bbl)		
Developed	15,332,804	—
Undeveloped	7,772,854	—
Total	23,105,658	—
Total (Boe)[1]		
Developed	90,078,116	43,445,637
Undeveloped	48,044,027	34,355,270
Total	138,122,143	77,800,907

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 GAAP.

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, 2022 and 2021 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, 2022 and 2021, respectively, in accordance with SEC guidelines. As of December 31, 2022, our reserves are based on an SEC average price of $90.15 per Bbl of WTI oil posted and $6.358 per MMBtu of Henry Hub natural gas. As of December 31, 2021, our reserves are based on an SEC average price of $63.04 per Bbl of WTI oil posted and $3.598 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.

[1] Six Mcf is deemed the equivalent of one Boe.

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

Standardized Measure of Discounted Future Net Cash Flows

December 31,	2022	2021	2020
Future cash inflows	$ 9,871,961,000	$ 4,853,709,000	$ 2,682,488,655
Future production costs	(2,751,896,250)	(1,395,437,250)	(821,515,126)
Future development costs	(647,196,750)	(347,757,000)	(244,323,270)
Future income taxes	(1,142,147,641)	(501,586,949)	(208,645,934)
Future net cash flows	5,330,720,359	2,608,927,801	1,408,004,325
10% annual discount for estimated timing of cash flows	(3,058,606,841)	(1,471,562,953)	(852,133,072)
Standardized Measure of Discounted Future Net Cash Flows	$ 2,272,113,518	$ 1,137,364,848	$ 555,871,253

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

Changes in Standardized Measure of Discounted Future Net Cash Flows

	2022	2021	2020
Beginning of the year	$ 1,137,364,848	$ 555,871,253	$ 923,175,051
Purchase of minerals in place	996,313,882	33,688,718	—
Extensions, discoveries and improved recovery	20,447,842	79,003,885	61,303,074
Development costs incurred during the year	67,454,522	17,513,180	29,916,746
Sales of oil and gas produced, net of production costs	(283,588,498)	(154,615,685)	(70,634,853)
Sales of minerals in place	—	(2,523,746)	—
Accretion of discount	133,209,763	63,810,764	92,838,323
Net changes in price and production costs	646,819,172	636,884,944	(368,974,767)
Net change in estimated future development costs	(53,253,626)	(44,357,751)	(3,883,985)
Revisions of previous quantity estimates	33,583,837	(22,259,508)	(66,213,586)
Changes in estimated timing of cash flows	(119,428,019)	86,845,188	(139,039,115)
Net change in income taxes	(306,810,205)	(112,496,394)	97,384,365
End of the Year	$ 2,272,113,518	$ 1,137,364,848	$ 555,871,253

Our proved reserves by state as of December 31, 2022 are summarized in the table below.

	Oil (Bbl)	Gas (Mcf)	Natural Gas Liquids (NGL) (Bbl)	Total (Boe)	% of Total Proved	Pre-tax PV-10 (In thousands)	Standardized Measure of Discounted Future Net Cash Flows (In thousands)	Future Capital Expenditures (In thousands)
Texas								
PD	54,825,249	105,172,422	15,175,702	87,529,688	63 %	$ 1,863,175	$ 1,526,269	$ 182,668
PUD	30,741,939	50,999,854	7,733,492	46,975,407	34 %	853,607	699,254	447,930
Total Proved:	85,567,188	156,172,276	22,909,194	134,505,095	97 %	$ 2,716,782	$ 2,225,523	$ 630,598
New Mexico								
PD	2,186,888	1,226,628	157,102	2,548,428	2 %	$ 43,506	$ 35,639	$ 1,985
PUD	950,667	471,545	39,362	1,068,620	1 %	13,369	10,952	14,614
Total Proved:	3,137,555	1,698,173	196,464	3,617,048	3 %	$ 56,875	$ 46,591	$ 16,599
Total								
PD	57,012,137	106,399,050	15,332,804	90,078,116	65 %	$ 1,906,681	$ 1,561,908	$ 184,653
PUD	31,692,606	51,471,399	7,772,854	48,044,027	35 %	866,976	710,206	462,544
Total Proved:	88,704,743	157,870,449	23,105,658	138,122,143	100 %	$ 2,773,657	$ 2,272,114	$ 647,197

Proved Reserves

As of December 31, 2022, we had approximately 138.1 MMBoe (one million Boe) of proved reserves, consisting of approximately 64% oil, 19% natural gas, and 17% natural gas liquids, as summarized in the table above. Our reserve estimates have not been filed with any Federal authority or agency (other than the SEC).

As of December 31, 2022, approximately 65% of the proved reserves have been classified as proved developed, or “PD” and the remaining 35% are proved undeveloped, or “PUD”.

As of December 31, 2022, our total proved reserves had a net pre-tax PV-10 value of approximately $2,773.7 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $2,272.1 million. Approximately $1,906.7 million and $1,561.9 million, respectively, of total proved reserves are associated with the PD reserves, which is approximately 69% of the total proved reserves’ pre-tax PV-10 value. The remaining $867.0 million and $710.2 million, respectively, are associated with PUD reserves.

Proved Undeveloped Reserves

Our reserve estimates as of December 31, 2022 include approximately 48.0 MMBoe as proved undeveloped reserves (PUD). As of December 31, 2021, our reserve estimates included approximately 34.4 MMBoe as proved undeveloped reserves. Below is a description of the changes in our PUD reserves from December 31, 2021 to December 31, 2022.

During the year ended December 31, 2022, we incurred costs of approximately $87.7 million to convert 26 properties from PUD to PD through development. These 26 properties produced 709 MBoe during the year ended December 31, 2022, and have reserves of 8,018 MBoe as of December 31, 2022.

The increase in proved undeveloped reserves was primarily attributable to the Stronghold Acquisition.

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 (Bbl)	Estimated Gas Reserves Developed (Mcf)	Estimated NGL Reserves Developed (Bbl)	Total Boe	Estimated Development Costs
2023	7,243,318	9,494,859	1,685,188	10,510,983	$ 102,822,989
2024	9,037,309	15,468,017	2,370,819	13,986,131	130,214,495
2025	8,631,583	17,046,317	2,403,159	13,875,795	125,779,913
2026	5,998,345	9,156,375	1,283,290	8,807,698	89,548,288
2027	782,049	305,832	30,399	863,420	14,178,133
	31,692,604	51,471,400	7,772,855	48,044,027	$ 462,543,818

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, Inc. ("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 3, 2023, 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 35 years of practical experience in petroleum engineering, with over 33 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.

Our 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 from the University of Texas with over 16 years of practical industry experience, including over 12 years of estimating and evaluating reserve information. He has been 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 reservoir 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, our 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; and
- utilizing experienced reservoir engineers or those under their direct supervision to prepare reserve estimates.

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, our 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, and the Executive Vice President of Land, Legal, Human Resources, and Marketing.

The Corporate Reserves department works closely with independent reserve engineers from CGA 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 reserve engineers that prepare estimates of proved reserves.

Summary of Oil and Natural Gas Properties and Projects

Acreage

The following table summarizes gross and net developed and undeveloped acreage as of December 31, 2022 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	64,774	54,959	3,905	2,337	68,679	57,296
Delaware Basin	18,729	18,437	—	—	18,729	18,437
Northwest Shelf	18,270	13,930	18,539	12,512	36,809	26,442
Total	101,773	87,326	22,444	14,849	124,217	102,175

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 the lessor and the lessee.

The following table sets forth gross and net undeveloped acreage, as of December 31, 2022, under lease which will 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:

	Undeveloped Acreage					
	2023		2024		2025	
	Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	480	234	1,420	1,221	860	49
Delaware Basin	—	—	—	—	—	—
Northwest Shelf	15,240	4,023	11,610	2,021	10,446	3,835
Total	15,720	4,257	13,030	3,242	11,306	3,884

Production History

The following table presents the historical information regarding our produced oil, natural gas and natural gas liquid volumes for the years ended December 31, 2022, 2021, and 2020:

	Years ended December 31,		
	2022	2021	2020
Oil (Bbls)			
Central Basin Platform	1,409,211	867,835	958,691
Delaware Basin	81,936	104,129	159,635
Northwest Shelf	1,968,693	1,714,976	1,683,202
Total	3,459,840	2,686,940	2,801,528
Natural Gas (Mcf)			
Central Basin Platform	1,563,808	171,690	268,495
Delaware Basin	96,516	288,918	468,177
Northwest Shelf	2,428,318	2,074,580	1,757,830
Total	4,088,642	2,535,188	2,494,502
Natural Gas Liquids (Bbls)[(1)]			
Central Basin Platform	227,996	—	—
Delaware Basin	3,718	—	—
Northwest Shelf	139,615	—	—
Total	371,329	—	—
Total production (Boe)			
Central Basin Platform	1,897,842	896,087	1,003,440
Delaware Basin	101,740	152,282	237,665
Northwest Shelf	2,513,028	2,060,739	1,976,173
Total	4,512,610	3,109,108	3,217,278
Daily production (Boe/d)			
Central Basin Platform	5,200	2,455	2,742
Delaware Basin	279	417	649
Northwest Shelf	6,885	5,646	5,399
Total	12,364	8,518	8,790

[(1)] Due to our acquisition of Stronghold's assets, which reported its volumes and revenues on a three-stream basis, beginning July 1, 2022, we began reporting volumes and revenues on a three-stream basis, separately reporting crude oil, natural gas, and natural gas liquid sales. For periods prior to July 1, 2022, sales and reserve volumes, prices, and revenues for natural gas liquids were presented with natural gas.

Production Prices and Production Costs

The following tables provides historical pricing and costs statistics for the years ended December 31, 2022, 2021, and 2020.

	Years ended December 31,		
	2022	2021	2020
Average sales price:			
Oil (per Bbl)			
Central Basin Platform	$ 91.72	$ 67.66	$ 39.64
Delaware Basin	95.97	65.98	35.00
Northwest Shelf	93.44	67.61	38.93
Total	$ 92.80	$ 67.56	$ 38.95
Natural gas (per Mcf)			
Central Basin Platform	$ 3.72	$ 4.63	$ 1.12
Delaware Basin	5.26	4.75	0.54
Northwest Shelf	5.09	6.08	1.91
Total	$ 4.57	$ 5.83	$ 1.57
Natural gas liquids (per Bbl)[(1)]			
Central Basin Platform	$ 20.02	$ —	$ —
Delaware Basin	27.16	—	—
Northwest Shelf	20.25	—	—
Total	$ 20.18	$ —	$ —
Total (per Boe)			
Central Basin Platform	$ 73.58	$ 66.42	$ 38.17
Delaware Basin	83.28	54.13	24.57
Northwest Shelf	79.24	62.38	34.86
Total	$ 76.95	$ 63.14	$ 35.13

(1) Due to our acquisition of Stronghold's assets, which reported its volumes and revenues on a three-stream basis, beginning July 1, 2022, we began reporting volumes and revenues on a three-stream basis, separately reporting crude oil, natural gas, and natural gas liquid sales. For periods prior to July 1, 2022, sales and reserve volumes, prices, and revenues for natural gas liquids were presented with natural gas.

	Years ended December 31,		
	2022	2021	2020
Average lease operating expenses (per Boe)			
Central Basin Platform	$ 13.81	$ 15.97	$ 15.44
Delaware Basin	44.86	32.75	19.13
Northwest Shelf	6.74	5.34	4.91
Total	$ 10.57	$ 9.75	$ 9.25
Average gathering, transportation and processing costs (per Boe)			
Central Basin Platform	$ —	$ —	$ —
Delaware Basin	—	—	—
Northwest Shelf	0.73	2.10	2.07
Total	$ 0.41	$ 1.39	$ 1.27
Average ad valorem taxes (per Boe)			
Central Basin Platform	$ 1.11	$ 1.17	$ 1.82
Delaware Basin	0.41	0.33	0.50
Northwest Shelf	1.00	0.57	0.60
Total	$ 1.04	$ 0.73	$ 0.97
Average production taxes (per Boe)			
Central Basin Platform	$ 3.64	$ 2.85	$ 1.67
Delaware Basin	3.97	2.45	1.30
Northwest Shelf	3.91	3.01	1.64
Total	$ 3.80	$ 2.93	$ 1.63

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 average natural gas liquids sales price amounts above are calculated by dividing revenue from natural gas liquids sales by the volume of natural gas liquids sold, in barrels “Bbl.”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, 2022 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
1,033	869	23	19	1,056	888

Drilling Activity

During 2022, we drilled 18.00 gross (17.35 net) horizontal San Andres wells in the Northwest Shelf (16.00 1.0-mile laterals and two 1.5-mile laterals.) In addition, we drilled 14.00 gross (14.00 net) wells in the Central Basin Platform, of which nine were horizontal San Andres wells in Andrews County, Texas (four 1.0-mile laterals and five 1.5-mile laterals) and five were vertical wells in Crane County, Texas. In addition, we also participated in three gross (0.33 net) non-operated wells in the Northwest shelf. These wells were successful and there were no dry wells.

The table below contains information regarding the number of operated wells drilled and participated in during the periods indicated.

	For the year ended December 31,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development						
Productive	32.00	31.35	11.00	9.91	6.00	5.61
Dry	—	—	—	—	—	—
Total						
Productive	32.00	31.35	11.00	9.91	6.00	5.61
Dry	—	—	—	—	—	—

The table below contains information regarding the number of non-operated wells drilled and participated in during the periods indicated.

	For the year ended December 31,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development						
Productive	3.00	0.33	2.00	0.23	1.00	0.11
Dry	—	—	—	—	—	—
Total						
Productive	3.00	0.33	2.00	0.23	1.00	0.11
Dry	—	—	—	—	—	—

Present Activities

We had no operated wells in the process of being drilled or completed as of December 31, 2022.

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 including lease operating expenses, gathering, processing and transportation ("GPT") and ad valorem, per Boe, were $12.02 and $11.88 for the years ended December 31, 2022 and 2021, respectively, and our average production taxes, per Boe, were $3.80 and $2.93 for the years ended December 31, 2022 and 2021, 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 for the years ended December 31, 2022, 2021 and 2020 are shown below:

	2022	2021	2020
Stronghold Acquisition	$ 177,823,787	$ —	$ —
Acquisition of proved properties	1,563,703	1,368,437	1,317,313
Divestiture of proved properties	(23,700)	(2,000,000)	—
Development costs	129,332,155	51,302,131	42,457,745
Total costs incurred	$ 308,695,945	$ 50,670,568	$ 43,775,058

Other Properties and Commitments

Effective January 1, 2021, the Company moved its corporate headquarters to The Woodlands, Texas. Prior to this, our principal offices were in Midland, Texas. Those offices now serve as an operations office. Our office space lease in Tulsa, Oklahoma was terminated as of March 31, 2021.

Item 3: Legal Proceedings

The Company is a defendant in a lawsuit in Harris County District Court, Houston, Texas, styled EPUS Permian Assets, LLC, v. Ring Energy, Inc., that was filed in July 2021. The plaintiff, EPUS Permian Assets, LLC, claims breach of contract, money had and received by fraudulent inducement, unjust enrichment and constructive trust. The plaintiff is requesting its forfeited deposit of $5,500,000 in connection with a proposed property sale by the Company plus related damages, and attorneys' fees and costs. The action relates to a proposed property sale by the Company to the plaintiff, which was extended by the Company on several occasions with the plaintiff ultimately failing to perform on the agreement and the Company keeping the deposit. The Company believes that the claims by the plaintiff are entirely without merit and is conducting a vigorous defense and counterclaim. The Company has filed an answer and a counterclaim denying the allegations and asserting affirmative defenses that would bar or substantially limit the plaintiff's claims, asserting breach of contract and requesting a declaratory judgment and attorneys' fees and costs. The parties have taken depositions and are conducting discovery.

Item 4: Mine Safety Disclosures

Not applicable.

PART II

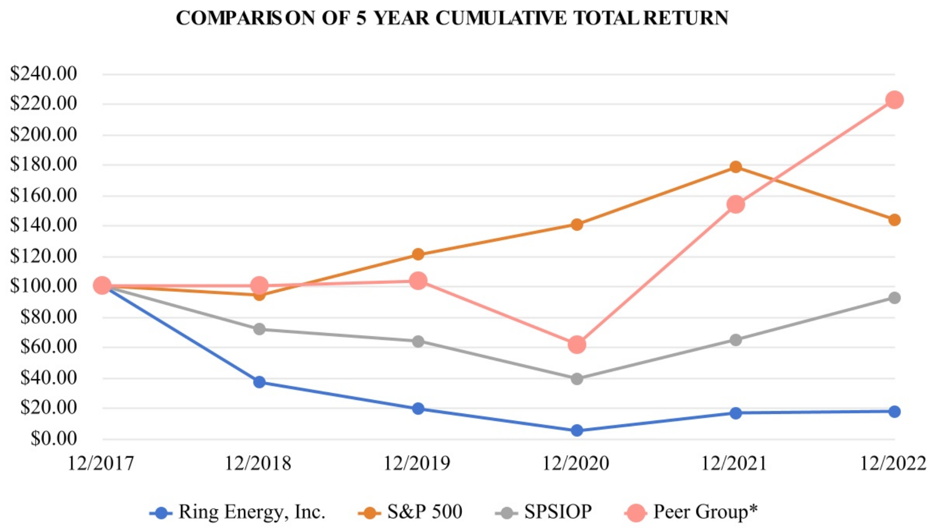
Item 5: Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for our Common Stock

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

Performance Graph

In 2022, we chose to compare our cumulative 5-year total return attained by stockholders on our common stock relative to the cumulative total returns of the S&P Oil and Gas Exploration and Production Select Industry Index ("SPSIOP"), instead of a peer group ("Peer Group"). If a company selects a different index or peer group from that used in the immediately preceding fiscal year, the company's stock performance must be compared with both the newly-selected index or peer group and the index used in the immediately preceding year. Accordingly, the following graph reflects a comparison of the cumulative total stockholder return of our common stock relative to the cumulative total returns of the S&P 500 Index, the SPSIOP and the 2021 Peer Group. The graph assumes the investment of $100 on December 31, 2017 in our common stock and each index and the reinvestment of all dividends, if any. This table is not intended to forecast future performance of our common stock.



* In 2021, the peer group consisted of: Abraxas Petroleum Corporation, Amplify Energy Corp., Civitas Resources, Inc., Earthstone Energy, Inc., Vital Energy, Inc. (formerly Laredo Petroleum, Inc.), Ranger Oil Corporation, SilverBow Resources, Inc., and W&T Offshore, Inc., each of which is 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 Act and will not be incorporated by reference into any registration statement 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 of the Exchange Act.

Record Holders

As of March 9, 2023, there were approximately 76 holders of record of our common stock. This is the number of record holders in the records of the transfer agent. It does not include holders of shares via brokerage accounts.

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 credit facility contains provisions limiting our ability to pay dividends until certain conditions are met.

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

The information required by this item was disclosed and reported under Item 3.02, Unregistered Sales of Equity Securities, of our Form 8-K dated August 30, 2022, filed with the SEC on September 6, 2022, which disclosure is incorporated herein by reference.

Issuer Repurchases

We did not make any repurchases of our equity securities during the year ended December 31, 2022.

Item 6: Reserved

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," "Forward Looking Statements" and elsewhere in this Annual Report.

Overview

Ring 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 the Permian Basin of Texas. 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.

Business Description and Plan of Operation

The Company is focused on balancing the need to reduce long-term debt and further developing our oil and gas properties to maintain or grow our annual production. We intend to achieve both through proper allocation of cash flow generated by our operations and potentially through the sale of non-core assets. We intend to continue evaluating potential transactions to acquire strategic producing assets with attractive acreage positions that can provide competitive returns for our shareholders.

2022 Developments and Highlights

Stronghold Acquisition

On July 1, 2022, Ring, as buyer, and Stronghold Energy II Operating, LLC, a Delaware limited liability company ("Stronghold OpCo") and Stronghold Energy II Royalties, LP, a Delaware limited partnership ("Stronghold RoyaltyCo", together with Stronghold OpCo, collectively, "Stronghold"), as seller, entered into a purchase and sale agreement (the "Purchase Agreement"). Pursuant to the Purchase Agreement, Ring acquired (the "Stronghold Acquisition") interests in oil and gas leases and related property of Stronghold consisting of approximately 37,000 net acres located in the Central Basin Platform of the Texas Permian Basin. On August 31, 2022, Ring completed the Stronghold Acquisition.

The fair value of consideration paid to Stronghold was approximately $394.0 million, of which $165.9 million, net of customary purchase price adjustments, was paid in cash at closing, $15.0 million was paid in cash after the six-month anniversary of the closing date of the Stronghold Acquisition. Shortly after closing, approximately $4.5 million was paid for inventory and vehicles and approximately $1.8 million was paid for August oil derivative settlements for certain novated hedges. The cash portion of the consideration was funded primarily from borrowings under a new fully committed revolving credit facility (the "Credit Facility") underwritten by Truist Securities, Citizens Bank, N.A., KeyBanc Capital Markets Inc., and Mizuho Bank, Ltd. The borrowing base of the $1.0 billion Credit Facility was increased from $350.0 million to $600.0 million at the closing of the Stronghold Acquisition. The remaining consideration consisted of 21,339,986 shares of Ring common stock and 153,176 shares of newly created Series A Convertible Preferred Stock, par value $0.001 ("Preferred Stock") which was converted into 42,548,892 shares of common stock on October 27, 2022. Please see "Note 12 - STOCKHOLDERS' EQUITY" for further discussion. In addition, Ring assumed $24.8 million of derivative liabilities,$1.7 million of items in suspense and $14.5 million in asset retirement obligations.

Drilling, Completion, and Recompletion

In the first quarter of 2022, we contracted a rig for our horizontal drilling program and began operations on January 31st. We drilled and completed three 1-mile horizontal wells and one 1.5-mile horizontal well in the Central Basin Platform. We then moved the rig to the Northwest Shelf and drilled two 1-mile horizontal wells. All wells drilled in the first quarter had a working interest of 100%.

In the second quarter of 2022, we drilled a total of nine wells, completed seven wells, and began the completion process on four wells, all in the Northwest Shelf. The first wells completed were the two 1-mile horizontal wells, which were drilled in the first quarter. Next, we drilled and completed two 1-mile horizontal wells with a working interest of

100%, two 1.5-mile horizontal wells with a working interest of approximately 98.7% and one 1-mile horizontal well with a working interest of approximately 75.4%. We also drilled and began the completion process on an additional four 1-mile horizontal wells. Two of the wells have a working interest of 100%, one has a working interest of approximately 87.9%, and the fourth has a working interest of 75%.

In the third quarter of 2022, we completed and placed on production the four aforementioned 1-mile horizontal wells in the Northwest Shelf, which were drilled in the second quarter. Next, we drilled and completed two 1.5-mile horizontal wells and one 1-mile horizontal well in the Central Basin Platform and two 1-mile horizontal wells in the Northwest Shelf, each with a working interest of 100%. During the last month of the quarter, we drilled and began the completion process on three 1-mile horizontal wells in the Northwest Shelf, two with a working interest of 99.7% and one with a working interest of 100%. In total, during the third quarter of 2022, we drilled eight, completed nine, and began the completion process on three horizontal wells. With the addition of the Stronghold Acquisition assets in the Central Basin Platform, we also performed three vertical well re-completions.

In the fourth quarter of 2022, we completed and placed on production the three aforementioned 1-mile horizontal wells in the Northwest Shelf. Next, we drilled and completed two 1-mile horizontal wells with a working interest of 100%, also in the Northwest Shelf. To complete the 2022 horizontal drilling program, we drilled and completed two 1.5-mile horizontal wells in the Central Basin Platform. In addition to the horizontal wells, we performed nine more vertical well re-completions and drilled and completed five new vertical wells on the Stronghold Acquisition assets located in Crane County, Texas, of the Central Basin Platform, all with a working interest of 100%.

In summary, for 2022, we drilled and completed 27 horizontal wells and 5 vertical wells, along with 12 vertical well re-completions on the Stronghold Acquisition assets. The table below sets forth our drilling and completion activities for 2022 by quarter through December 31, 2022.

Quarter	Area	Wells Drilled	Wells Completed	Recompletions
1Q 2022	Central Basin Platform (Horizontal)	4	4	—
	Central Basin Platform (Vertical)	—	—	—
	Northwest Shelf	2	—	—
2Q 2022	Central Basin Platform (Horizontal)	—	—	—
	Central Basin Platform (Vertical)	—	—	—
	Northwest Shelf	9	7	—
3Q 2022	Central Basin Platform (Horizontal)	3	3	—
	Central Basin Platform (Vertical)	—	—	3
	Northwest Shelf	5	6	—
4Q 2022	Central Basin Platform (Horizontal)	2	2	—
	Central Basin Platform (Vertical)	5	5	9
	Northwest Shelf	2	5	—

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly the price of crude oil and natural gas 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 improvement of oil and natural gas prices experienced in 2022 continues to demonstrate commodity price volatility and we believe oil and natural gas prices will continue to be volatile for the foreseeable future. The ability to find and develop sufficient amounts of crude oil and natural gas 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,	2022	2021	2020
Net production:			
Oil (Bbls)	3,459,840	2,686,940	2,801,528
Natural gas (Mcf)	4,088,642	2,535,188	2,494,502
Natural gas liquids (Bbls)	371,329	—	—
Net sales:			
Oil	$ 321,062,672	$ 181,533,093	$ 109,113,557
Natural gas	18,693,631	14,772,873	3,911,581
Natural gas liquids	7,493,234	—	—
Average sales price:			
Oil (per Bbl)	$ 92.80	$ 67.56	$ 38.95
Natural gas (per Mcf)	4.57	5.83	1.57
Natural gas liquids (Bbl)	20.18	—	—
Production costs and expenses:			
Lease operating expenses	$ 47,695,351	$ 30,312,399	$ 29,753,413
Gathering, transportation and processing costs	1,830,024	4,333,232	4,090,238
Ad valorem taxes	4,670,617	2,276,463	3,125,222
Production taxes	17,125,982	9,123,420	5,228,090
Other costs and operating expenses:			
Depreciation, depletion and amortization expense	$ 55,740,767	$ 37,167,967	$ 43,010,660
Ceiling test impairment	—	—	277,501,943
Asset retirement obligation accretion	983,432	744,045	906,616
Operating lease expense	363,908	523,487	1,196,372
General and administrative expense (excluding stock-based compensation)	19,933,092	13,649,782	11,509,888
Stock-based compensation expense	7,162,231	2,418,323	5,364,162
Other income (expense):			
Interest (expense)	$ (23,167,729)	$ (14,490,474)	$ (17,617,614)
Gain (loss) on derivative contracts	(21,532,659)	(77,853,141)	21,366,068
Deposit forfeiture income	—	—	5,500,000

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Oil sales. Oil sales increased approximately $139.5 million from $181.5 million in 2021 to $321.1 million in 2022. The oil sales increase was the result of an increase in the average realized per barrel oil price from $67.56 in 2021 to

$92.80 in 2022 and an increase in sales volume from 2,686,940 barrels of oil in 2021 to 3,459,840 barrels of oil in 2022. The increased average realized per barrel oil price was a result of the significantly higher oil price during the first eight months of 2022. The increased sales volumes were a direct result of assets acquired in the Stronghold Acquisition, which resulted in higher volumes for the last four months of 2022, as well as organic growth from capital expenditures that were $78.0 million greater in 2022 than in 2021.

Natural gas sales. Natural gas sales increased approximately $3.9 million from $14.8 million in 2021 to $18.7 million in 2022. The natural gas sales volume increased from 2,535,188 Mcf in 2021 to 4,088,642 Mcf in 2022 and the average realized per Mcf gas price decreased from $5.83 in 2021 to $4.57 in 2022. The sales volume increase was due to the aforementioned increase in capital expenditures as well as the Stronghold Acquisition, which closed August 31, 2022. The price decrease was driven by the Company's change in reporting presentation from two-stream (oil and natural gas) to three-stream (oil, natural gas and natural gas liquids) beginning July 1, 2022.

Natural gas liquids sales. Natural gas liquids sales increased approximately $7.5 million from $0.0 million in 2021 to $7.5 million in 2022. NGL sales volumes in were 371,329 barrels of NGLs compared to zero barrels in 2021, due to the Company's change in reporting presentation for its natural gas products, which are presented on a three-stream basis beginning July 1, 2022. The average realized price per barrel of NGLs was $20.18 in 2022.

Lease operating expenses. Our total lease operating expenses ("LOE") increased from $30,312,399 in 2021 to $47,695,351 in 2022 and increased on a Boe basis from $9.75 in 2021 to $10.57 in 2022. These per Boe amounts are calculated by dividing our total lease operating expenses by our total volume sold, in Boe. LOE increased primarily due to a 45% increase in production of 1,403,502 Boe year-over-year, as well as increased costs for goods and services due to increased Permian activity.

Gathering, transportation and processing costs. Our total gathering, transportation and processing costs ("GTP") decreased from $4,333,232 in 2021 to $1,830,024 in 2022 and decreased on a Boe basis from $1.39 in 2021 to $0.41 in 2022. GTP costs decreased due to costs classified as a reduction to oil and natural gas sales revenues, due to a natural gas processing entity beginning to take control of transportation at the wellhead beginning May 1, 2022.

Ad valorem taxes. Our total ad valorem taxes increased from $2,276,463 in 2021 to $4,670,617 in 2022 and increased on a Boe basis from $0.73 in 2021 to $1.04 in 2022. Ad valorem taxes increased primarily due to the increase in taxed commodity prices from the prior year, as well as $783,159 for the properties acquired in the Stronghold Acquisition.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales were 4.65% during 2021 and increased to 4.93% in 2022. Overall, the percentage was consistent year over year, with a slight increase due to proportionately higher gas revenues which are taxed at a higher rate. 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 (currently only Texas and New Mexico), and on the possibility that any state may raise its production tax rates.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased from $37,167,967 in 2021 to $55,740,767 in 2022 due to an increase in our total estimated costs of property as well as an increase of 1,403,502 in Boe produced. Our average depreciation, depletion and amortization per Boe increased from $11.95 per Boe during 2021 to $12.35 per Boe during 2022. These per Boe amounts are calculated by dividing our total depreciation, depletion and amortization expense by our total Boe volumes sold.

Asset retirement obligation accretion. Our asset retirement obligation ("ARO") accretion increased from $744,045 in 2021 to $983,432 in 2022. This was a result of the 32 additional wells added from 2022 drilling activities as well as ARO accretion associated with the properties acquired in the Stronghold Acquisition, offset by wells plugged and abandoned during the year.

Operating lease expense. Our operating lease expense decreased from $523,487 in 2021 to $363,908 in 2022 due to the month to month leases for office equipment and compressors used in operations on which the Company had previously elected to apply ASU 2016-02. The office equipment and compressors are not subject to ASU 2016-02 based on the agreement and nature of use. The costs have been recorded as short-term lease costs and amounts included in lease operating expenses beginning in the second quarter of 2021.

General and administrative expenses (including share-based compensation). General and administrative expenses increased from $16,068,105 in 2021 to $27,095,323 in 2022. The increase was primarily related to a $4,743,908 increase in share-based compensation, as well as increases in salaries and bonuses, all attributed to a nearly doubled headcount from 2021 to 2022 to support our growth. Other cost increases include software maintenance, rent, insurance, and environmental sustainability. The 2022 expenses also included non-recurring acquisition-related costs of $2.1 million.

Interest expense. Interest expense increased from $14,490,474 in 2021 to $23,167,729 in 2022. The increase was the result of a combination of higher interest rates during the second half of 2022, with a weighted average interest rate of 5.8% in 2022 and 4.4% in 2021, and having higher amounts outstanding on our credit facility throughout 2022, with a weighted average daily debt of approximately $308.7 million in 2021 compared to approximately $344.0 million in 2022, particularly due to the additional debt incurred for the Stronghold Acquisition.

Gain (loss) on derivative contracts. During 2022, the Company incurred a loss on derivative contracts of $21,532,659. During 2021, the Company recorded a loss on derivative contracts of $77,853,141. For the derivative contract settlements, the Company recorded a realized loss of $52,768,154 during 2021 and a realized loss of $62,525,954 during 2022, The increase of $9,757,800 in the realized loss was a result of the rise of crude oil prices during 2022, which was above the fixed prices of the contracts. For the marked-to-market contracts, the Company recorded an unrealized gain of $40,993,295 during 2022 and an unrealized loss of $25,084,987 during 2021. This change in unrealized derivatives was due to the roll off of unfavorable contracts during 2022, as well as the Company's purchase of more favorable contracts during 2022.

Benefit from (Provision for) income taxes. The benefit from (provision for) income taxes changed from a provision of $90,342 for 2021 to a provision of $8,408,724 for 2022. The current year federal tax expense was the result of certain existing deferred tax assets that will not be offset by existing deferred tax liabilities as a result of the 80% limitation on the utilization of net operating losses incurred after 2017.

Net income (loss). The Company had a net income of $3,322,892 in 2021 compared to net income of $138,635,025 in 2022. The increase in net income was due primarily to the increase in oil, natural gas, and natural gas liquids revenues, as well as the reduction in derivative contract losses, offset by increases in lease operating expenses, depletion, general and administrative expenses, and interest expense.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Oil and natural gas sales. Oil and natural gas sales revenue increased from 2020 levels by approximately $83.3 million to $196.3 million in 2021. Oil sales increased approximately $72.4 million and natural gas sales increased approximately $10.9 million. The oil sales increase was the result of an increase in the average realized per barrel oil price from $38.95 in 2020 to $67.56 in 2021, slightly offset by a decrease in sales volume from 2,801,528 barrels of oil in 2020 to 2,686,940 barrels of oil in 2021. These per barrel amounts are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels. Despite the few months of shut in or curtailed production due to oil price destabilizing from the COVID-19 pandemic, volumes in 2020 significantly benefited from the large amount of capital expenditures incurred in the previous year. Likewise, the lower capital expenditures in 2020 resulted in a negative impact to 2021 volumes due to natural well declines. Capital expenditures in 2021 helped offset declines, but not enough to overcome the full impact from the reduced capital expenditures in 2020.

The natural gas sales volume increased slightly from 2,494,502 Mcf in 2020 to 2,535,188 Mcf in 2021 and the average realized per Mcf gas price increased from $1.57 in 2020 to $5.83 in 2021. The price increase was driven by a steady increase in NGL prices and a 92% increase in the underlying Henry Hub gas price, which included the impact of Winter Storm Uri in 2021. These per Mcf amounts are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. Natural gas sales volumes in 2021 were positively impacted by higher volumes associated with reservoir de-pressurization at the Northwest Shelf properties which were partially offset by purchaser inability to receive gas volumes at certain times throughout the year due to downtime or mechanical issues effecting efficiencies with their facilities.

Lease operating expenses. Our total lease operating expenses ("LOE") increased slightly from $29,753,413 in 2020 to $30,312,399 in 2021 and increased on a Boe basis from $9.25 in 2020 to $9.75 in 2021. These per Boe amounts are calculated by dividing our total lease operating expenses by our total volume sold, in Boe. LOE increased due to the higher amount of activity in 2021 compared to the lack of activity resulting from the oil price destabilization due to the COVID-19 pandemic in 2020.

Gathering, transportation and processing costs. Our total gathering, transportation and processing costs (“GTP”) increased slightly from $4,090,238 in 2020 to $4,333,232 in 2021 and increased on a Boe basis from $1.27 in 2020 to $1.39 in 2021. GTP costs increased due to the higher gas volumes processed in the Northwest Shelf.

Ad valorem taxes. Our total ad valorem taxes decreased from $3,125,222 in 2020 to $2,276,463 in 2021 and decreased on a Boe basis from $0.97 in 2020 to $0.73 in 2021. Ad valorem taxes decreased due to the Company’s compliance department’s annual detailed review of each property’s current production, ownership, and lease operating expenses, which resulted in cost savings for the taxes assessed.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales were 4.63% during 2020 and increased to 4.65% in 2021. The slight increase was due to higher Texas gas revenue which is taxed at 7.5%. 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 (currently only Texas and New Mexico), and on the possibility that any state may raise its production tax rates.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense decreased from $43,010,660 in 2020 to $37,167,967 in 2021. The decrease was the result of an increase in our total reserves and an average decrease of total property cost from the impairment in 2020, resulting in a reduction to our average depreciation, depletion and amortization rate from $13.37 per Boe during 2020 to $11.95 per Boe during 2021. 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 did not record a ceiling test write-down during 2021. 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, 2021, adjusted for market differentials, per SEC guidelines. 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 was reflected as ceiling test impairments in the accompanying Statements of Operations. The primary reason for the write-down was a reduction in the oil price used for calculating the reserves from $52.19 in 2019 to $36.04 in 2020.

Asset retirement obligation accretion. Our asset retirement obligation (“ARO”) accretion decreased from $906,616 in 2020 to $744,045 in 2021. This was a result of the reduction of ARO liabilities from the sale of certain assets in the first quarter of 2021 and plugging activities conducted throughout the year.

Operating lease expense. Our operating lease expense decreased from $1,196,372 in 2020 to $523,487 in 2021 due to the month to month leases for office equipment and compressors used in our operations on which we had previously elected to apply ASU 2016-02. The office equipment and compressors are not subject to ASU 2016-02 based on the agreement and nature of use. The costs are recorded as short-term lease costs and amounts included in Lease operating expenses. The Company terminated its Oklahoma lease as of March 31, 2021 and negotiated a reduction to its Midland office lease.

General and administrative expenses (including share-based compensation). General and administrative expenses decreased from $16,874,050 in 2020 to $16,068,105 in 2021. The decrease was primarily related to a $2,945,839 reduction in share-based compensation, offset by increases in salaries, accounting expenses, and non-recurring costs associated with investor relations.

Interest expense. Interest expense decreased from $17,617,614 in 2020 to $14,490,474 in 2021. The decrease was the result of having lower amounts outstanding on our credit facility throughout 2021.

Gain (loss) on derivative contracts. During 2020, the Company recorded a gain on derivative contracts of $21,366,068. During 2021, the Company incurred a loss on derivative contracts of $77,853,141. The significant change was due to the rise of crude oil prices during 2021, which was above the fixed price of the contracts.

Deposit forfeiture income. During 2021, the Company did not earn 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.

Benefit from (Provision for) income taxes. The benefit from (provision for) income taxes changed from a benefit of $6,001,176 for 2020 to a provision of $90,342 for 2021. The change was primarily the result of a full valuation allowance on federal taxes in 2021 with only state tax activity recognized.

Net income (loss). The Company had a net loss of ($253,411,828) in 2020 compared to net income of $3,322,892 in 2021. The change in net income (loss) was primarily the result of the ceiling test write-down in 2020.

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 source of cash in 2022 was from funds generated from the sale of oil and natural gas production. These cash flows were primarily used to fund our capital expenditures. We believe the combination of the sources of capital discussed will continue to be adequate to meet our short and long-term liquidity needs.

Credit Facility. On July 1, 2014, the Company entered into a Credit Agreement with SunTrust Bank (now Truist), as lender, issuing bank and administrative agent for several banks and other financial institutions and lenders (the “Administrative Agent”), (which was amended several times) that provided for a maximum borrowing base of $1 billion with security consisting of substantially all of the assets of the Company. In April 2019, the Company amended and restated the Credit Agreement with the Administrative Agent (as amended and restated, the “Credit Facility”).

On August 31, 2022, the Company modified its Credit Facility through a Second Amended and Restated Credit Agreement, extending the maturity date of the facility to August 2026. In conjunction with the Stronghold Acquisition, with the newly acquired assets put up for collateral, the Company established a borrowing base of $600 million. The borrowing base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The borrowing base is redetermined semi-annually on each May 1 and November 1. The borrowing base is subject to reduction 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 syndicate was modified to add five lenders, replacing five exiting lenders. Rather than Eurodollar loans, the reference rate on the Second Amended and Restated Credit Agreement is the Standard Overnight Financing Rate (“SOFR”). Beginning on the June 30, 2023 financial statements and compliance certification delivery date, the Second Amended and Restated Credit Agreement will allow for the Company to declare dividends for its equity owners, subject to certain limitations. These limitations include (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio, as defined in the Second Amended and Restated Credit Agreement, does not exceed 2.00 to 1.00, (iii) the amount of such payments does not exceed Available Free Cash Flow, (iv) the Borrowing Base Utilization Percentage is not greater than 80%, and (v) a Responsible Officer certifies that the other four conditions are satisfied.

The interest rate on each SOFR Loan will be the adjusted term SOFR for the applicable interest period plus a margin between 3.0% and 4.0% (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 Second Amended and Restated Credit Agreement) plus 0.5% per annum, (iii) the adjusted term SOFR 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 2.0% and 3.0% per annum (depending on the then-current level of borrowing base usage).

The Second Amended and Restated Credit Agreement 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, exploration expenses, and all other non-cash charges acceptable to the Administrative Agent) of not more than 3.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Second Amended and Restated Credit Agreement) of 1.0 to 1.0.

The Company is required to maintain on a rolling 24 months basis, hedging transactions in respect of crude oil and natural gas, on not less than 50% of the projected production from its proved, developed, producing oil and gas. If the borrowing base utilization is less than 25% at the hedge testing date and the leverage ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall be 0% from such hedge testing date to the next succeeding hedge testing date. If the borrowing base utilization percentage is equal to or greater than 25%, but less than 50% and the leverage ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall be 25% from such hedge testing date to the next succeeding hedge testing date.

The Second Amended and Restated Credit Agreement also contains other customary affirmative and negative covenants and events of default. As of December 31, 2022, $415,000,000 was outstanding on the Credit Facility. The Company is in compliance with all covenants contained in the Second Amended and Restated Credit Agreement as of December 31, 2022.

Equity Offering. 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. 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 for the Common Warrants exercised in 2020 aggregated $19,379,832.

The Common Shares of 9,575,800 and 3,500,000 were issued in 2020, as shown in our Statements of Stockholders' Equity. The Pre-Funded Warrants of 3,300,000 were exercised and common stock was issued in 2020 and the Pre-Funded Warrants of 13,428,500 were exercised and common stock was issued in 2021, as shown in our Statements of Stockholders' Equity. Of the aforementioned 6,800,000 Common Warrants, all remained outstanding as of December 31, 2021 and 2022. Of the aforementioned 23,004,300 Common Warrants, 442,600 were exercised and common stock was issued in 2021 and 10,253,907 were exercised and common stock was issued in 2022, as shown in our Statements of Stockholders' Equity.

Issuance of Common Stock and Convertible Preferred Stock for Stronghold Acquisition. As part of the consideration for the Stronghold Acquisition, on August 31, 2022 the Company issued 21,339,986 shares of common stock and 153,176 shares of newly created Series A Convertible Preferred Stock, which was converted into 42,548,892 shares of common stock on October 27, 2022.

Cash Flows. Historically, our primary sources of cash have been from operations, equity offerings and borrowings on our Credit Facility. During 2022, 2021, and 2020 we had cash inflow from operations of $197.0 million, $72.7 million, and $72.2 million, respectively. During the three years ended December 31, 2022, we financed $28.0 million through proceeds from the sale of stock. During 2022, 2021, and 2020, we had proceeds from drawdowns on our Credit Facility of $636.0 million, $60.2 million, and $26.5 million, respectively. We primarily used this cash to fund our capital expenditures and development aggregating $405.2 million over the three years ended December 31, 2022. Additionally, during 2022, 2021 and 2020, we used $511.0 million, $83.2 million and $80.0 million, respectively, to reduce the outstanding balance on our Credit Facility. As of December 31, 2022, we had cash on hand of $3.7 million and negative working capital of $78.0 million, compared to cash on hand of $2.4 million and negative working capital of $46.9 million as of December 31, 2021 and cash on hand of $3.6 million and negative working capital of $16.1 million as of December 31, 2020.

Contractual Obligations. The Company maintains a Credit Facility which currently has a $600.0 million borrowing base. The outstanding balance on that Credit Facility as of December 31, 2022 is $415.0 million, which will require repayment or refinancing at or prior to maturity in August 2026.

The Company leases office spaces in The Woodlands, Texas and Midland, Texas. The Woodlands office is under a five-and-a-half-year lease beginning January 15, 2021. The Midland office lease was amended effective October 1, 2022, with the revised five-year lease ending September 30, 2027.

The Company has financing leases for vehicles with varying maturity dates through October 2025. Future lease payments through October 2025 aggregate $1,900,595.

Subsequent Events

Stronghold acquisition - On February 28, 2023, as discussed in "Note 5 - ACQUISITIONS & DIVESTITURES," the deferred cash consideration of $15.0 million in cash was paid to Stronghold in accordance with terms set forth in the Purchase Agreement for the Stronghold Acquisition. In addition on March 1, 2023, the holdback amount of approximately $8.3 million which was held in escrow in accordance with the terms set forth in the Purchase Agreement for the Stronghold Acquisition was distributed to Stronghold.

Common stock issued pursuant to warrant exercise - On February 2, 2023, the Company issued 2,517,427 shares of common stock pursuant to the exercise of Common Warrants with an exercise price of $0.80. Gross and net proceeds were $2,013,942. On March 1, 2023, the Company issued 2,000,000 shares of common stock pursuant to the exercise of Common Warrants with an exercise price of $0.80. Gross and net proceeds were $1,600,000.

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, 2022, 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, as well as considerations of recent accounting pronouncements, are detailed in "Note 1 - ORGANIZATION, BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES" 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 - REVENUE RECOGNITION" 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 2020, the Company recorded a non-cash write-down of the carrying value of the Company's proved oil and natural gas properties as a result of a ceiling test limitation of approximately $277.5 million, 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 2021 or 2022.

Our estimates of reserves and future cash flow as of December 31, 2022 and 2021 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, 2022 and 2021, respectively, in accordance with SEC guidelines. As of December 31, 2022, our reserves are based on an SEC average price of $90.15 per Bbl of WTI oil posted and $6.358 per MMBtu Henry Hub natural gas. As of December 31, 2021, our reserves are based on an SEC average price of $63.04 per Bbl of WTI oil posted and $3.598 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 the Company files its tax returns.

In assessing the Company's deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is assessed at each reporting period and is dependent upon the generation of future taxable income and the Company's ability to utilize operation loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies.

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 2022 ranged from a monthly average low of $75.33 per barrel to a monthly average high of $114.86 per barrel. Natural gas prices we received during 2022 ranged from a monthly average low of $2.16 per Mcf to a monthly average high of $9.78 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. The following table summarizes the Company's hedges in place on a monthly basis by commodity type. See "Note 8 - DERIVATIVE FINANCIAL INSTRUMENTS" to our financial statements for further information.

Month	Oil Hedges (WTI) Average BBL/day	Gas Hedges (Henry Hub) Average MMBtu/day
January 2023	5,180	3,86
February 2023	5,145	11,65
March 2023	5,113	11,58
April 2023	4,832	11,25
May 2023	4,802	11,18
June 2023	4,774	11,11
July 2023	4,497	10,80
August 2023	4,471	10,73
September 2023	4,447	10,66
October 2023	4,423	10,35
November 2023	4,400	10,29
December 2023	4,379	10,23
January 2024	4,150	6,50
February 2024	4,132	6,50
March 2024	4,113	6,50
April 2024	4,096	6,25
May 2024	4,081	6,25
June 2024	4,066	6,25
July to September 2024	3,750	6,00
October to December 2024	4,000	6,00

Customer Credit Risk

Our principal exposure to credit risk is through receivables from the sale of our oil and natural gas production (approximately $40.1 million as of December 31, 2022). 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 year ended December 31, 2022, sales to three customers, Phillips, NGL Crude, and Enterprise represented 68%, 13% and 5%, respectively, of our oil, natural gas, and natural gas liquids revenues. As of December 31, 2022, Phillips represented 69% of our accounts receivable, NGL Crude represented 7% of our accounts receivable and Enterprise represented 10% 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.

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, 2022, we had $415.0 million outstanding on our Credit Facility with a weighted average interest rate of 5.8%. A 1% change in the interest rate on our Credit Facility would result in an estimated $4.2 million change in our annual interest expense. See "Note 10 - REVOLVING LINE OF CREDIT" in the Footnotes to the financial statements for more information on the Company’s interest rates on our Credit Facility.

Currently, we do 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 on Accounting and Financial Disclosure

None.

Item 9A: Controls and Procedures

Evaluation of disclosure controls and procedures.

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2022, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2022, our disclosure controls and procedures are 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.

There were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2022 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 is 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, 2022, our internal control over financial reporting is effective based on those criteria.

The independent registered public accounting firm, Grant Thornton LLP, has audited the financial statements and internal control over financial reporting included in this Annual Report on Form 10-K, and has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2022. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2022, is set forth below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Ring Energy, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Ring Energy, Inc. (a Nevada corporation) (the “Company”) as of December 31, 2022, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the financial statements of the Company as of and for the year ended December 31, 2022, and our report dated March 9, 2023 expressed an unqualified opinion on those financial statements.

Basis for opinion

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

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

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Houston, Texas
March 9, 2023

Item 9B: Other Information

None.

Item 9C: Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

None.

PART III

Item 10: Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated by reference herein from the Company's 2023 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022. 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 Company's 2023 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022. 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 Company's 2023 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022. 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 Company's 2023 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022. 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 Accountant Fees and Services

The information required by this item is incorporated by reference herein from the Company's 2023 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022. 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 and Financial Statement Schedules

Exhibit Number	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Here-with
2.1	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	
2.2	Purchase and Sale Agreement dated July 1, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, a Delaware limited liability company (“Stronghold OpCo”) and Stronghold Energy II Royalties, LP, a Delaware limited partnership, including the following Exhibits thereto: Exhibit I – Form of Registration Rights Agreement, Exhibit K – Form of Nomination Agreement, Exhibit L – Form of Certificate of Designation and Exhibit M – Form of Lock-Up Agreement	8-K	001-36057	2.1	7/8/22	
2.2(a)	First Amendment to Purchase and Sale Agreement by and among Stronghold Energy II Operating, LLC, Stronghold Energy II Royalties, LP, and Ring Energy, Inc., dated August 4, 2022	8-K	001-36057	2.1	8/9/22	
3.1	Articles of Incorporation (as amended)	10-K	000-53920	3.1	4/1/13	
3.1(a)	Certificate of Amendment to the Articles of Incorporation, as amended, of Ring Energy, Inc.	8-K	001-36057	3.1	12/17/21	
3.2	Bylaws of Ring Energy, Inc. as amended April 13, 2021	8-K	001-36057	3.1	4/15/21	
3.3	Certificate of Designation of the Series A Convertible Preferred Stock dated August 30, 2022	8-K	001-36057	3.1	9/6/22	
3.4	Certificate of Withdrawal of Certificate of Designation filed with the Secretary of State of Nevada effective October 31, 2022	8-K	001-36057	3.1	10/31/22	
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	10.16	3/16/21	
4.3	Securities Purchase Agreement, dated October 27, 2020	8-K	001-36057	4.1	10/29/20	
10.1*	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	
10.2*	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	
10.3*	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	
10.4*	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	12/22/20	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Here-with
		Form	File No.	Exhibit	Filing Date	
10.5*	Ring Energy Inc. Long Term Incentive Plan, as Amended	8-K	000-53920	99.3	1/24/13	
10.6*	Form of Option Grant for Long-Term Incentive Plan	10-Q	000-53920	10.2	8/14/12	
10.7	Credit Agreement dated July 1, 2014 with SunTrust Bank	8-K	001-36057	10.1	7/3/14	
10.8	First Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	6/29/15	
10.9	Second Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	7/29/15	
10.10	Third Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	5/20/16	
10.11	Fourth Amendment to Credit Agreement with SunTrust Bank	10-K	001-36057	10.16	3/16/21	
10.12	Fifth Amendment to Credit Agreement with SunTrust	8-K	001-36057	10.1	6/19/18	
10.13	Amended and Restated Credit Agreement with SunTrust Bank	10-Q	001-36057	10.2	5/8/19	
10.14	First Amendment to Amended and Restated Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	12/9/19	
10.15	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	
10.16	Third Amendment to Amended and Restated Credit Agreement with Truist Bank	8-K	001-36057	10.1	12/29/20	
10.17	Fourth Amendment to Amended and Restated Credit Agreement with Truist Bank dated June 10, 2021	8-K	001-36057	10.1	6/16/21	
10.18	Fifth Amendment to Amended and Restated Credit Agreement with Truist Bank dated June 25, 2021	8-K	001-36057	10.1	6/25/21	
10.19*	Executive Employment and Severance Agreement, dated as of October 26, 2020, by and between the Company and Travis T. Thomas	8-K	001-36057	10.1	3/26/21	
10.20	Registration Rights Agreement dated August 31, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, and Stronghold Energy II Royalties, LP.	8-K	001-36057	10.1	9/6/22	
10.21	Lock-up Agreement dated August 31, 2022, by and between Ring Energy, Inc. and Stronghold Energy II Operating, LLC.	8-K	001-36057	10.2	9/6/22	
10.22	Director Nomination Agreement dated August 31, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, and Stronghold Energy II Royalties, LP.	8-K	001-36057	10.3	9/6/22	
10.23	Second Amended and Restated Credit Agreement dated August 31, 2022, by and among Ring Energy, Inc., Truist Bank, and the Lenders from time to time party thereto	8-K	001-36057	10.4	9/6/22	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Here-with
10.24*	Ring Energy, Inc. 2021 Omnibus Incentive Plan	DEF 14A	001-36057		4/22/21	
10.25*	Form of Performance Stock Unit Agreement	8-K	001-36057	10.1	11/30/21	
10.26*	Form Restricted Stock Unit Agreement (employees)	8-K	001-36057	10.1	2/23/23	
10.27*	Form of Restricted Stock Unit Agreement (non-employee directors)	8-K	001-36057	10.2	2/23/23	
14.1	Code of Ethics	8-K	000-53920	14.1	1/24/13	
23.1	Consent of Cawley, Gillespie & Associates, Inc.					X
23.2	Consent of Grant Thornton LLP					X
23.3	Consent of Eide Bailly LLP					X
24.1	Power of Attorney (included as part of the signature pages of this report)					X
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

Item 16: Form 10-K Summary

None.

SIGNATURES

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

Ring Energy, Inc.

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

Date: March 9, 2023

KNOW ALL PERSONS BY THESE PRESENTS, that each individual whose signature appears below constitutes and appoints Paul D. McKinney, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission, hereby ratifying and confirming his signature as he may be signed by his or her said attorney to any and all amendments to said Annual Report on Form 10-K.

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

/s/ Paul D. McKinney	*/s/ Thomas L. Mitchell*
Mr. Paul D. McKinney Chief Executive Officer and Director (Principal Executive Officer) Date: March 9, 2023	Mr. Thomas L. Mitchell Director Date: March 9, 2023
/s/ Travis T. Thomas	*/s/ Anthony B. Petrelli*
Mr. Travis T. Thomas Chief Financial Officer (Principal Financial Officer) Date: March 9, 2023	Mr. Anthony B. Petrelli Director Date: March 9, 2023
/s/ Regina Roesener	*/s/ Clayton E. Woodrum*
Mrs. Regina Roesener Director Date: March 9, 2023	Mr. Clayton E. Woodrum Director Date: March 9, 2023
/s/ Richard E. Harris	*/s/ John A. Crum*
Mr. Richard E. Harris Director Date: March 9, 2023	Mr. John A. Crum Director Date: March 9, 2023
/s/ Roy I. Ben-Dor	*/s/ David S. Habachy*
Mr. Roy I. Ben-Dor Director Date: March 9, 2023	Mr. David S. Habachy Director Date: March 9, 2023

RING ENERGY, INC.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Ring Energy, Inc.

Opinion on the financial statements

We have audited the accompanying balance sheets of Ring Energy, Inc. (a Nevada corporation) (the "Company") as of December 31, 2022 and 2021, the related statements of operations, stockholders' equity, and cash flows for each of the two years in the period ended December 31, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 9, 2023 expressed an unqualified opinion.

Basis for opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence 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. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matters

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. 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 matter below, providing separate opinions on the critical audit matter or on the accounts or disclosures to which it relates.

The development of estimated proved crude oil and natural gas reserves used in the calculation of depletion, depreciation and amortization expense under the full cost method of accounting and the valuation of crude oil and natural gas properties in the 2022 Stronghold Acquisition (herein referred to as "the crude oil and natural gas reserves")

As described further in Note 1 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting, which requires management to make estimates of proved crude oil and natural gas reserve volumes and future net revenues to record depletion, depreciation and amortization expense. Additionally, as described in Note 5 to the financial statements, the Company acquired significant oil and natural gas properties through an asset acquisition. Crude oil and natural gas reserves are a significant input to the determination of the acquisition date value of crude oil and natural gas properties acquired by the Company in the asset acquisition. To estimate the volume of proved crude oil and natural gas reserves and future net revenue, 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 crude oil and natural gas reserves is impacted by management's judgments and estimates regarding the financial performance of wells associated with proved crude oil and natural gas reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion, depreciation and amortization expense. We identified the estimation of proved reserves of oil and gas properties as it relates to the recognition of depletion, depreciation and amortization expense and recording the values of properties acquired in the 2022 Stronghold Acquisition as a critical audit matter.

The principal consideration for our determination that the estimation of proved crude oil and natural gas reserves as it relates to the recognition of depletion, depreciation and amortization expense and the recording of oil and natural gas property values in the 2022 Stronghold acquisition is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future net revenues of the Company's proved reserves could have a significant impact on the measurement of depletion, depreciation and amortization expense and the acquisition date values of oil and natural gas properties. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

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

- We tested the design and operating effectiveness of controls relating to management's estimation of proved crude oil and natural gas reserves for the purpose of estimating depletion, depreciation and amortization expense and acquisition date value of crude oil and natural gas properties.

- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved crude oil and natural gas reserve volumes, and read the reserve report prepared by the Company's specialists.

- To the extent key inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, including, but not limited to: historical pricing differentials, operating costs, estimated capital costs, and ownership interests, we tested management's process for determining the assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by performing the following:

    - We compared the estimated pricing differentials used in the reserve report to prices realized by the Company related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials.

    - As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we compared the pricing differentials used in the reserve report to the differentials provided by the seller, and performed analytical procedures by comparing the differentials in the reserve report to actual differentials realized subsequent to the acquisition close date.

    - We tested models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs.

    - As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we recalculated the operating costs in the reserve report based on the model provided by the seller, and performed analytical procedures by comparing the operating costs in the reserve report to operating costs realized subsequent to the acquisition close date.

    - We evaluated the method used to determine the estimated future development costs used in the reserve report and compared management's estimates to amounts expended for recently drilled and completed wells.

    - As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we compared the estimated future development costs in the reserve report to the model provided by the seller, and we performed analytical procedures by comparing the future development costs in the reserve report to actual development costs incurred subsequent to the acquisition close date.

- We tested the working and net revenue interests used in the reserve report by inspecting land, legal and division order records.
- We evaluated evidence supporting the amount of 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.
- We applied analytical procedures to production forecasts in the reserve report by comparing to historical actual results.
- As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we applied analytical procedures to production forecasts by comparing the remaining forecast in 2022 in the reserve report to actual results subsequent to the acquisition close date.
- As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition, we utilized internal valuation specialists to assist with evaluating certain assumptions, such as risk-adjustment factors, as compared to industry surveys and publicly available market data.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2021.

Houston, Texas
March 9, 2023

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

We have audited the accompanying statements of operations, stockholders' equity, and cash flows of Ring Energy, Inc. (Ring Energy) for the year 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 results of its operations and its cash flows for the year ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the entity's management. Our responsibility is to express an opinion on these financial statements based on our audit. 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud.

Our audit included performing procedures to assess the risk 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 audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the 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.

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. Hansen, Barnett and Maxwell, P.C., who joined Eide Bailly LLP in 2013, had served as the Company's auditor since 2012.

Eide Bailly LLP

Denver, Colorado
March 16, 2021

RING ENERGY, INC.
BALANCE SHEETS

As of December 31,	2022	2021
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,712,526	$ 2,408,316
Accounts receivable	42,448,719	24,026,807
Joint interest billing receivable	983,802	2,433,811
Derivative assets	4,669,162	—
Inventory	9,250,717	—
Prepaid expenses and other assets	2,101,538	938,029
Total Current Assets	63,166,464	29,806,963
Properties and Equipment		
Oil and natural gas properties, full cost method	1,463,838,595	883,844,745
Financing lease asset subject to depreciation	3,019,476	1,422,487
Fixed assets subject to depreciation	3,147,125	2,089,722
Total Properties and Equipment	1,470,005,196	887,356,954
Accumulated depreciation, depletion and amortization	(289,935,259)	(235,997,307)
Net Properties and Equipment	1,180,069,937	651,359,647
Operating lease asset	1,735,013	1,277,253
Derivative assets	6,129,410	—
Deferred financing costs	17,898,973	1,713,466
Total Assets	$ 1,268,999,797	$ 684,157,329
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 111,398,268	$ 46,233,452
Financing lease liability	709,653	316,514
Operating lease liability	398,362	290,766
Derivative liabilities	13,345,619	29,241,588
Notes payable	499,880	586,410
Deferred cash payment	14,807,276	—
Total Current Liabilities	141,159,058	76,668,730
Non-current Liabilities		
Deferred income taxes	8,499,016	90,292
Revolving line of credit	415,000,000	290,000,000
Financing lease liability, less current portion	1,052,479	343,727
Operating lease liability, less current portion	1,473,897	1,138,319
Derivative liabilities	10,485,650	—
Asset retirement obligations	30,226,306	15,292,054
Total Liabilities	607,896,406	383,533,122
Commitments and contingencies		
Stockholders' Equity		
Preferred stock - $0.001 par value; 50,000,000 shares authorized; no shares issued or outstanding	—	—
Common stock - $0.001 par value; 225,000,000 shares authorized; 175,530,212 shares and 100,192,562 shares issued and outstanding, respectively	175,530	100,193
Additional paid-in capital	775,241,114	553,472,292
Accumulated deficit	(114,313,253)	(252,948,278)
Total Stockholders' Equity	661,103,391	300,624,207
Total Liabilities and Stockholders' Equity	$ 1,268,999,797	$ 684,157,329

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

RING ENERGY, INC.
STATEMENTS OF OPERATIONS

For the years ended December 31,	2022	2021	2020
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 347,249,537	$ 196,305,966	$ 113,025,138
Costs and Operating Expenses			
Lease operating expenses	47,695,351	30,312,399	29,753,413
Gathering, transportation and processing costs	1,830,024	4,333,232	4,090,238
Ad valorem taxes	4,670,617	2,276,463	3,125,222
Oil and natural gas production taxes	17,125,982	9,123,420	5,228,090
Depreciation, depletion and amortization	55,740,767	37,167,967	43,010,660
Ceiling test impairment	—	—	277,501,943
Asset retirement obligation accretion	983,432	744,045	906,616
Operating lease expense	363,908	523,487	1,196,372
General and administrative expense	27,095,323	16,068,105	16,874,050
Total Costs and Operating Expenses	155,505,404	100,549,118	381,686,604
Income (Loss) from Operations	191,744,133	95,756,848	(268,661,466)
Other Income (Expense)			
Interest income	4	1	8
Interest (expense)	(23,167,729)	(14,490,474)	(17,617,614)
Gain (loss) on derivative contracts	(21,532,659)	(77,853,141)	21,366,068
Deposit forfeiture income	—	—	5,500,000
Net Other Income (Expense)	(44,700,384)	(92,343,614)	9,248,462
Income (Loss) Before Provision for Income Taxes	147,043,749	3,413,234	(259,413,004)
Benefit from (Provision for) Income Taxes	(8,408,724)	(90,342)	6,001,176
Net Income (Loss)	$ 138,635,025	$ 3,322,892	$ (253,411,828)
Basic Earnings (Loss) per share	$ 1.14	$ 0.03	$ (3.48)
Diluted Earnings (Loss) per share	$ 0.98	$ 0.03	$ (3.48)

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

RING ENERGY, INC.
STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount			
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
Common stock and warrants issued for cash, net	—	$ —	$ (65,000)	$ —	$ (65,000)
Exercise of pre-funded warrants issued in offering	13,428,500	13,429	—	—	13,429
Exercise of common warrants issued in offering	442,600	443	353,637	—	354,080
Options exercised	100,000	100	199,900	—	200,000
Restricted stock vested	785,357	785	(785)	—	—
Shares to cover tax withholdings	(132,182)	(132)	132	—	—
Payments to cover tax withholdings	—	—	(385,330)	—	(385,330)
Share-based compensation	—	—	2,418,323	—	2,418,323
Net (loss)	—	—	—	3,322,892	3,322,892
Balance, December 31, 2021	100,192,562	$ 100,193	$ 553,472,292	$ (252,948,278)	$ 300,624,207
Exercise of common warrants issued in offering	10,253,907	10,254	8,192,872	—	8,203,126
Options exercised	100,000	100	(100)	—	—
Shares elected to be withheld for options exercised	(47,506)	(48)	48	—	—
Restricted stock vested	1,310,894	1,311	(1,311)	—	—
Shares to cover tax withholdings for restricted stock vested	(168,523)	(169)	169	—	—
Payments to cover tax withholdings for restricted stock vested	—	—	(521,199)	—	(521,199)
Common stock issuance for Stronghold	21,339,986	21,340	69,120,215	—	69,141,555
Conversion of mezzanine preferred shares for Stronghold	42,548,892	42,549	137,815,897	—	137,858,446
Share-based compensation	—	—	7,162,231	—	7,162,231
Net income	—	—	—	138,635,025	138,635,025
Balance, December 31, 2022	175,530,212	$ 175,530	$ 775,241,114	$ (114,313,253)	$ 661,103,391

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

RING ENERGY, INC.
STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2022	2021	2020
Cash Flows From Operating Activities			
Net income (loss)	$ 138,635,025	$ 3,322,892	$ (253,411,828)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	55,740,767	37,167,967	43,010,660
Ceiling test impairment	—	—	277,501,943
Asset retirement obligation accretion	983,432	744,045	906,616
Amortization of deferred financing costs	2,706,021	665,882	1,190,109
Share-based compensation	7,162,231	2,418,323	5,364,162
Bad debt expense	242,247	—	—
Shares issued for services	—	—	23,800
Deferred income tax expense (benefit)	8,720,992	265,479	(3,975,170)
Excess tax expense (benefit) related to share-based compensation	(312,268)	(175,187)	(2,026,006)
(Gain) loss on derivative contracts	21,532,659	77,853,141	(21,366,068)
Cash received (paid) for derivative settlements, net	(62,525,954)	(52,768,154)	22,522,591
Changes in assets and liabilities:			
Accounts receivable	(17,214,150)	(9,483,639)	7,896,517
Inventory	(5,597,845)	—	—
Prepaid expenses and other assets	(1,163,509)	(541,920)	3,586,146
Accounts payable	50,808,461	15,449,215	(8,380,594)
Settlement of asset retirement obligation	(2,741,380)	(2,186,832)	(683,623)
Net Cash Provided by Operating Activities	196,976,729	72,731,212	72,159,255
Cash Flows From Investing Activities			
Payments for the Stronghold Acquisition	(177,823,787)	—	—
Payments to purchase oil and natural gas properties	(1,563,703)	(1,368,437)	(1,317,313)
Payments to develop oil and natural gas properties	(129,332,155)	(51,302,131)	(42,457,745)
Payments to acquire or improve fixed assets subject to depreciation	(319,945)	(568,832)	(55,339)
Sale of fixed assets subject to depreciation	134,600	—	—
Proceeds from divestiture of oil and natural gas properties	23,700	2,000,000	—
Net Cash (Used in) Investing Activities	(308,881,290)	(51,239,400)	(43,830,397)
Cash Flows From Financing Activities			
Proceeds from revolving line of credit	636,000,000	60,150,000	26,500,000
Payments on revolving line of credit	(511,000,000)	(83,150,000)	(80,000,000)
Proceeds from issuance of common stock and warrants	8,203,126	367,509	19,383,131
Proceeds from option exercise	—	200,000	—
Payments for taxes withheld on vested restricted shares	(521,199)	(385,330)	—
Proceeds from notes payable	1,323,354	1,297,718	—
Payments on notes payable	(1,409,884)	(711,308)	—
Payment of deferred financing costs	(18,891,528)	(104,818)	(355,049)
Reduction of financing lease liabilities	(495,098)	(325,901)	(282,928)
Net Cash Provided by (Used in) Financing Activities	113,208,771	(22,662,130)	(34,754,846)
Net Increase (Decrease) in Cash	1,304,210	(1,170,318)	(6,425,988)
Cash at Beginning of Period	2,408,316	3,578,634	10,004,622
Cash at End of Period	$ 3,712,526	$ 2,408,316	$ 3,578,634

RING ENERGY, INC.
STATEMENTS OF CASH FLOWS (CONTINUED)

For the Years Ended December 31,	2022	2021	2020
Supplemental Cash Flow Information			
Cash paid for interest	$ 19,818,623	$ 14,110,421	$ 16,911,344
Noncash Investing and Financing Activities			
Asset retirement obligation incurred during development	$ 353,008	$ 171,390	$ 99,436
Asset retirement obligation acquired	14,538,550	662,705	—
Asset retirement obligation revision of estimate	—	435,419	34,441
Asset retirement obligation sold	—	(2,934,126)	—
Operating lease assets obtained in exchange for new operating lease liability	754,894	839,536	823,727
Operating lease asset revision	—	(621,636)	—
Financing lease assets obtained in exchange for new financing lease liability	952,101	—	—
Stock issued in property acquisition returned in final settlement	—	—	103,385
Capitalized expenditures attributable to drilling projects financed through current liabilities	9,179,003	309,365	1,415,073
Supplemental Schedule for Stronghold Acquisition			
Investing Activities - Cash Paid			
Cash paid by bank to Stronghold on closing	$ 121,392,455	$ —	$ —
Deposit in escrow	46,500,000	—	—
Direct transaction costs	9,162,143	—	—
Cash paid for realized August oil derivative losses	1,777,925	—	—
Cash paid for inventory and fixed assets acquired	4,527,103	—	—
Cash received for post-close adjustments, net	(5,535,839)	—	—
Payments for the Stronghold Acquisition	$ 177,823,787	$ —	$ —
Investing Activities - Noncash			
Assumption of suspense liability	1,651,596	—	—
Assumption of derivative liabilities	24,784,406	—	—
Assumption of asset retirement obligation	14,538,550	—	—
Deferred cash payment at fair value	14,807,276	—	—
Financing Activities - Noncash			
Common stock issued for acquisition	69,141,555	—	—
Convertible preferred stock issued for acquisition	$ 137,858,446	$ —	$ —

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., 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. 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.

Reclassifications – Certain prior period amounts relating to components of operating expense have been reclassified to conform to current year presentation within "Costs and Operating Expenses" in the Statements of Operations. Additionally, certain prior amounts associated with realized and unrealized gains (losses) have been reclassified within the Statements of Operations and Statements of Cash Flows to conform with current year presentation.

Use of Estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("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 $3,462,526 and $1,936,805 as of December 31, 2022 and 2021, respectively. The Company places its cash with a high credit quality financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to significant credit risk in this area.

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. Accounts receivable from joint interest owners or purchasers outstanding longer than the contractual payment terms are considered past due. For the years ended December 31, 2022, 2021, and 2020, the Company provided for bad debt expense of $242,247, $0, and $0 respectively, associated with its joint interest billing receivable. As of December 31, 2022 and 2021, the Company's allowance for credit losses was $242,247 and $0, respectively, associated with its joint interest billing receivable.

The Company accounts for natural gas production imbalances using the sales method, which recognizes revenue on all natural gas sold even though the natural gas volumes sold may be more or less than the Company's ownership entitles it to sell. Liabilities are recorded for imbalances greater than the Company's proportionate share of remaining estimated natural gas reserves. The Company recorded no imbalances as of December 31, 2022 or 2021.

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.

Inventory - During 2022, the Company purchased materials and supplies inventories in bulk to lock in prices with certain vendors. Additionally, as a part of the Stronghold Acquisition (discussed further in "Note 5 - ACQUISITIONS & DIVESTITURES"), the Company acquired an inventory yard with significant amounts of inventory. Inventory is added to the books upon the purchase of supplies (inclusive of freight and sales tax costs) to use on well sites, and inventory is reduced by material transfers for inventory usage based on the initial invoiced value. We report the balance of our inventory at the lower of cost or market value. Inventory balances are excluded from the Company's calculation of depletion.

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. All of the Company's capitalized costs, excluding inventory, are 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. Dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs.

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, 2022, 2021, and 2020.

	For the Years Ended December 31,		
	2022	**2021**	**2020**
Depletion	$ 55,029,956	$ 36,735,070	$ 42,634,294
Depletion rate, per barrel-of-oil-equivalent (Boe)	$ 12.19	$ 11.82	$ 13.25

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 year ended December 31, 2020, the Company recognized an impairment on oil and natural gas properties as a result of the ceiling test in the amount of $277,501,943. No impairment was recorded for the years ended December 31, 2022 or 2021.

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	3-5 years
Office equipment and software	3-7 years
Equipment	5-10 years
Automobiles	4 years

Depreciation expense was $205,600, $432,897, and $376,366 for the years ended December 31, 2022, 2021, and 2020, respectively.

Notes Payable – During 2022, the Company renewed its directors and officers, control of well, and cybersecurity policies, and funded the premiums with three promissory notes with a total face value after down payments of $1,323,354. As of December 31, 2022, the notes payable balance included within current liabilities on the balance sheet is $499,880. During 2021, the Company obtained external insurance for the same policies and funded the premiums by signing three promissory notes. The annual percentage rate (APR) for these notes is 4.08%. For the years ended December 31, 2022 and 2021, interest paid related to notes payable was $25,579 and $17,824, respectively, included within "Interest (expense)" in the Statements of Operations.

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 - REVENUE RECOGNITION" 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 carryforwards. 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.

Accounting for Uncertainty in Income Taxes – In accordance with GAAP, 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, 2018 and after remain subject to examination. The Company’s federal income tax returns for the years ended December 31, 2007 and after remain subject to examination to the extent of the net operating loss (NOL) carryforwards. The Company’s franchise tax returns in Texas remain subject to examination for 2017 and after. 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 GAAP. 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.

Three-Stream Reporting - Beginning July 1, 2022, the Company began reporting volumes and revenues on a three-stream basis, separately reporting crude oil, natural gas, and natural gas liquids ("NGLs") sales. For periods prior to July 1, 2022, sales and reserve volumes, prices, and revenues for NGLs were presented with natural gas. This represents a change in our accounting and reporting presentation necessitated by a change in the underlying facts and circumstances surrounding the Stronghold Acquisition, as Stronghold has historically reported its revenues on a three-stream basis. As clarified in the interpretive guidance of ASC 250, such changes should not be applied on a retrospective basis. Accordingly, we began reporting on a three-stream basis prospectively, beginning July 1, 2022.

Leases - The Company accounts for its leases in accordance with ASU 2016-02, Leases (Topic 842), effective January 1, 2019. The Company made accounting policy elections to not capitalize leases with a lease term of twelve months or less (i.e., short term leases) and to not separate lease and non-lease components for all asset classes. The Company 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.

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, 2022, sales to three customers represented 68%, 13% and 5%, respectively, of total oil, natural gas, and natural gas liquids sales. As of December 31, 2022, sales outstanding from these three customers represented 69%, 7% and 10%, respectively, of accounts receivable. During the year ended December 31, 2021, sales to three customers represented 76%, 7% and 6%, respectively, of total oil and natural gas sales. As of December 31, 2021, sales outstanding from these three customers represented 75%, 8% and 4%, respectively, of accounts receivable. 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.

Share-Based Employee Compensation – The Company has outstanding stock option grants and restricted stock awards to directors, officers and employees, which are described more fully in "Note 13 - EMPLOYEE STOCK OPTIONS, RESTRICTED STOCK AWARD PLAN AND 401(K)". The Company recognizes the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award and recognizes the related compensation expense over the period during which an employee is required to provide service in exchange for the award, which is generally the vesting period.

Share-Based Compensation to Non-Employees – The Company accounts for share-based compensation issued to non-employees as either the fair value of the consideration received or the fair value of the equity instruments issued, whichever is more reliably measurable. The measurement date for these issuances is the earlier of (i) the date at which a commitment for performance by the recipient to earn the equity instruments is reached or (ii) the date at which the recipient's performance is complete.

Share-based compensation incurred for the years ended December 31, 2022, 2021, and 2020 was $7,162,231, $2,418,323, and $5,364,162, 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. Refer to "Note 8 - DERIVATIVE FINANCIAL INSTRUMENTS" for further details.

Recently Adopted Accounting Pronouncements – In August 2018, the FASB issued 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.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, followed by other related ASUs that provided targeted improvements (collectively "ASU 2016-13"). ASU 2016-13 provides financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The guidance is to be applied using a modified retrospective method and is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. The Company adopted ASU 2016-13 on January 1, 2020. The adoption of ASU 2016-13 did not have a material impact to the Company's financial statements or disclosures.

In December 2019, the FASB released ASU No. 2019-12 ("ASU 2019-12"), *Income Taxes* (Topic 740) – Simplifying the Accounting for Income Taxes, which removes certain exceptions for recognizing deferred taxes for investments, performing intraperiod allocation and calculating income taxes in interim periods. The ASU also adds guidance to reduce complexity in certain areas, including recognizing deferred taxes for tax goodwill and allocating taxes to members of a consolidated group. The amended standard is effective for fiscal years beginning after December 15, 2020. The adoption of ASU 2019-12 did not have a material impact to the Company's financial statements or disclosures.

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

In August 2020, the FASB issued ASU No. 2020-06, "Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40)" ("ASU 2020-06"). ASU 2020-06 was issued to reduce the complexity associated with accounting for certain financial instruments with characteristics of liabilities and equity. The guidance may be applied using either a modified retrospective or a fully retrospective method. ASU 2020-06 is effective for fiscal years beginning after December 15, 2021, with early adoption permitted. The Company adopted ASU 2020-06 effective January 1, 2022. The adoption and implementation of this ASU did not have a material impact on the Company's financial statements.

Recent Accounting Pronouncements – In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* ("ASU 2020-04"), which provides optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships, subject to meeting certain criteria, that reference LIBOR or another rate that is expected to be discontinued. ASU 2020-04 will be in effect through December 31, 2022. In January 2021, issued ASU No. 2021-01, *Reference Rate Reform (Topic 848): Scope* ("ASU 2021-01"), to provide clarifying guidance regarding the scope of Topic 848. ASU 2020-04 was issued to provide optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the effects of) reference rate reform on financial reporting. In December 2022, the FASB issued ASU 2022-06, "*Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848"* ("ASU 2022-06"), which defers the sunset date of Topic 848 from December 31, 2022 to December 31, 2024. Beginning August 31, 2022, under the Company's Second Amended and Restated Credit Agreement, the Company's interest rates were transitioned from the LIBOR to the SOFR (Standard Overnight Financing Rate) reference rate. At this time, the Company does not plan to enter into additional contracts using LIBOR as a reference rate.

In October 2021, the FASB issued ASU 2021-08, "*Business Combinations (Topic 805) – Accounting for Contract Assets and Contract Liabilities from Contracts with Customers"* ("ASU 2021-08"). This update requires the acquirer in a business combination to record contract asset and liabilities following Topic 606 – "Revenue from Contracts with Customers" at acquisition as if it had originated the contract, rather than at fair value. This update is effective for public business entities beginning after December 15, 2022, with early adoption permitted. The Company continues to evaluate the provisions of this update, but it does not believe the adoption will have a material impact on its financial position, results of operations or liquidity.

NOTE 2 – REVENUE RECOGNITION

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 Company has utilized the practical expedient in Accounting Standards Codification ("ASC") 606-10-50-14, which states an entity is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's sales contracts, each unit of production delivered to a customer represents a separate performance obligation, therefore, future volumes to be delivered are wholly unsatisfied and disclosure of transaction price allocated to remaining performance obligation is not required. The transaction price includes variable consideration as product pricing is based on published market prices and adjusted for contract specified differentials such as quality, energy content and transportation. The guidance does not require that the transaction price be fixed or stated in the contract. Estimating the variable consideration does not require significant judgment and the Company 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.

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 at the net price received when control transfers to the purchaser at the point of delivery and it is probable the Company will collect the consideration it is entitled to receive.

Natural gas and NGL 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 and NGLs (natural gas liquids) at the wellhead. The midstream processing entity gathers and processes the natural gas and NGLs and remits proceeds to the Company for the resulting sale of natural gas and NGLs. Under these processing agreements, the Company recognizes revenue when control transfers to the purchaser at the point of delivery and it is probable the Company will collect the consideration it is entitled to receive. As such, the Company accounts for any fees and deductions as a reduction of the transaction price.

Until April 30, 2022, under the Company's natural gas sales processing contracts for the bulk of our Northwest Shelf assets, the Company delivered unprocessed natural gas to a midstream processing entity at the wellhead. However, the Company maintained ownership of the gas through processing and received proceeds from the marketing of the resulting products. Under this processing agreement, the Company recognized the fees associated with the processing as an expense rather than netting these costs against Oil and Natural Gas Revenues in the Statements of Operations. Beginning May 1, 2022, these contracts were combined into one contract, and it was modified so that the Company no longer maintained ownership of the gas through processing. Accordingly, the Company from that point on accounts for any such fees and deductions as a reduction of the transaction price.

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

	For the years ended December 31,		
	2022	2021	2020
Oil, Natural Gas, and Natural Gas Liquids Revenues			
Oil	$ 321,062,672	$ 181,533,093	$ 109,113,557
Natural gas	18,693,631	14,772,873	3,911,581
Natural gas liquids	7,493,234	—	—
Total oil, natural gas, and natural gas liquids revenues	$ 347,249,537	$ 196,305,966	$ 113,025,138

NOTE 3 – LEASES

The Company has operating leases for our offices in Midland, Texas and The Woodlands, Texas. The Midland office is under a five-year lease which began January 1, 2021. The Midland office lease was amended effective October 1, 2022, with the revised five-year lease ending September 30, 2027. Beginning January 15, 2021, the Company entered into a five-and-a-half-year sub-lease for office space in The Woodlands, Texas. The future payments associated with these operating leases are reflected below. During the years ended December 31, 2020 and 2021 the Company had an operating lease with Arenaco, LLC for its Tulsa, Oklahoma office. The Tulsa lease was terminated as of March 31, 2021, with payments made until the end of February 2021. Refer to "Note 14 - RELATED PARTY TRANSACTIONS" for further details.

The Company 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 (i.e. not capitalize). The office equipment and compressors are not subject to ASU 2016-02 based on the agreement and nature of use. 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 within Lease operating expenses, shown below.

The Company has financing leases for vehicles. These leases have a term of 36 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, 2022 are as follows:

	2023	2024	2025	2026	2027
Operating lease payments (1)	$ 474,464	$ 482,328	$ 494,692	$ 398,096	$ 216,000
Financing lease payments (2)	793,723	727,451	379,421	—	—

(1) The weighted average discount rate as of December 31, 2022 for operating leases was 4.50%. Based on this rate, the future lease payments above include imputed interest of $193,321. The weighted average remaining term of operating leases was 4.29 years.

(2) The weighted average discount rate as of December 31, 2022 for financing leases was 5.82%. Based on this rate, the future lease payments above include imputed interest of $138,463. The weighted average remaining term of financing leases was 2.41 years. The following table represents a reconciliation between the undiscounted future cash flows in the table above and the operating and financing lease liabilities disclosed in the Balance Sheets:

	As of December 31, 2022	2021
Operating lease liability, current portion	398,362	290,766
Operating lease liability, non-current portion	1,473,897	1,138,319
Operating lease liability, total	**1,872,259**	**1,429,085**
Total undiscounted future cash flows (sum of future operating lease payments)	2,065,580	1,577,786
Imputed interest	193,321	148,701
Undiscounted future cash flows less imputed interest	**1,872,259**	**1,429,085**
Financing lease liability, current portion	709,653	316,514
Financing lease liability, non-current portion	1,052,479	343,727
Financing lease liability, total	**1,762,132**	**660,241**
Total undiscounted future cash flows (sum of future financing lease payments)	1,900,595	692,091
Imputed interest	138,463	31,850
Undiscounted future cash flows less imputed interest	**1,762,132**	**660,241**

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

		2022
Operating lease costs	$	363,908
Short-term lease costs (1)	$	2,618,405
Financing lease costs:		
Amortization of financing lease assets (2)	$	505,211
Interest on lease liabilities (3)	$	48,472

(1) Amount included in Lease operating expenses

(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,		**2022**		**2021**		**2020**
Net Income (Loss)	$	138,635,025	$	3,322,892	$	(253,411,828)
Basic Weighted-Average Shares Outstanding		121,264,175		99,387,028		72,891,310
Effect of dilutive securities:						
Stock options		83,384		75,897		—
Restricted stock units		2,040,181		1,613,810		—
Performance stock units		248,206		—		—
Common warrants		18,118,722		20,116,440		—
Diluted Weighted-Average Shares Outstanding		141,754,668		121,193,175		72,891,310
Basic Earnings (Loss) per Share	$	1.14	$	0.03	$	(3.48)
Diluted Earnings (Loss) per Share	$	0.98	$	0.03	$	(3.48)

Stock options to purchase 70,500, 113,659, and 465,500 shares of common stock were excluded from the computation of diluted earnings per share during the years ended December 31, 2022, 2021 and 2020, respectively, as their effect would have been anti-dilutive. Also excluded from the computation of diluted earnings per share were 13,512, 20,610, and 2,144,617 shares of unvested restricted stock units during the years ended December 31, 2022, 2021 and 2020, respectively, as their effect would have been anti-dilutive. Unvested performance stock units of 814,255, 94,270, and —

were excluded from the computation of diluted earnings per share during the years ended December 31, 2022, 2021, and 2020, 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 for the year ended December 31, 2020 as they were exercisable for a nominal amount and so were treated as if they were exercised at issuance. These shares were exercised in January 2021 and were included in the beginning shares outstanding for the calculation of Basic Weighted-Average Shares Outstanding for the year ended December 31, 2021.

NOTE 5 – ACQUISITIONS & DIVESTITURES

Andrews County Acquisition

The Company entered into a Purchase, Sale and Exchange Agreement dated February 1, 2021, effective January 1, 2021, with an unrelated party, covering the sale and exchange of certain oil and gas interests in Andrews County, Texas. Upon the sale and transfer of wells and leases between the two parties, the Company received a cash consideration of $2,000,000 and reduced the Company's asset retirement obligations by $2,934,126 for the properties sold and added $662,705 of asset retirement obligations for the wells acquired.

Stronghold Acquisition

On July 1, 2022, Ring, as buyer, and Stronghold Energy II Operating, LLC, a Delaware limited liability company ("Stronghold OpCo") and Stronghold Energy II Royalties, LP, a Delaware limited partnership ("Stronghold RoyaltyCo", together with Stronghold OpCo, collectively, "Stronghold"), as seller, entered into a purchase and sale agreement (the "Purchase Agreement"). Pursuant to the Purchase Agreement, Ring acquired (the "Stronghold Acquisition") interests in oil and gas leases and related property of Stronghold consisting of approximately 37,000 net acres located in the Central Basin Platform of the Texas Permian Basin. On August 31, 2022, Ring completed the Stronghold Acquisition.

The fair value of consideration paid to Stronghold was approximately $394.0 million, of which $165.9 million, net of customary purchase price adjustments, was paid in cash at closing, $15.0 million will be payable in cash after the six-month anniversary of the closing date of the Stronghold Acquisition. Shortly after closing, approximately $4.5 million was paid for inventory and vehicles and approximately $1.8 million was paid for August oil derivative settlements for certain novated hedges. The cash portion of the consideration was funded primarily from borrowings under a new fully committed revolving credit facility (the "Credit Facility") underwritten by Truist Securities, Citizens Bank, N.A., KeyBanc Capital Markets Inc., and Mizuho Bank, Ltd. The borrowing base of the $1.0 billion Credit Facility was increased from $350.0 million to $600.0 million at the closing of the Stronghold Acquisition. The remaining consideration consisted of 21,339,986 shares of Ring common stock and 153,176 shares of newly created Series A Convertible Preferred Stock, par value $0.001 ("Preferred Stock") which was converted into 42,548,892 shares of common stock on October 27, 2022. Please see "Note 12 - STOCKHOLDERS' EQUITY" for further discussion. In addition, Ring assumed $24.8 million of derivative liabilities, $1.7 million of items in suspense and $14.5 million in asset retirement obligations.

Purchase Price Allocation

The Stronghold Acquisition has been accounted for as an asset acquisition in accordance with ASC Topic 805 - Business Combinations. The fair value of the consideration paid by Ring and allocation of that amount to the underlying assets acquired, on a relative fair value basis, was recorded on Ring's books as of the date of the closing of the Stronghold Acquisition. Additionally, costs directly related to the Stronghold Acquisition were capitalized as a component of the purchase price. Determining the fair value of the assets and liabilities acquired requires judgment and certain assumptions to be made, the most significant of these being related to the valuation of Stronghold's oil and gas properties. The inputs and assumptions related to the oil and gas properties are categorized as level 3 in the fair value hierarchy.

The following table represents the preliminary allocation of the total cost of the Stronghold Acquisition to the assets acquired and liabilities assumed as of the Stronghold Acquisition date:

Consideration:		
Shares of Common Stock issued		21,339,986
Common Stock price as of August 31, 2022	$	3.24
Common Stock Consideration	$	69,141,555
Shares of Preferred Stock issued		153,176
Aggregate Liquidation Preference	$	153,176,000
Conversion Price	$	3.60
As-Converted Shares of Common Stock		42,548,892
Common Stock Price as of August 31, 2022	$	3.24
Preferred Stock Consideration	$	137,858,446
Cash consideration:		
Closing amount paid to Stronghold		121,392,455
Escrow deposit paid		46,500,000
Cash paid for inventory and fixed assets		4,527,103
Cash paid for realized losses on August oil derivatives		1,777,925
Cash received for post-close adjustments, net		(5,535,839)
Total cash consideration		168,661,644
Fair value of deferred payment liability		14,807,276
Post-close settlement to be paid to Stronghold		3,511,170
Fair value of consideration paid to seller		393,980,091
Direct transaction costs		9,162,143
Total consideration	$	403,142,234
Fair value of assets acquired:		
Oil and natural gas properties		439,589,683
Inventory and fixed assets		4,527,103
Amount attributable to assets acquired	$	444,116,786
Fair value of liabilities assumed:		
Suspense liability		1,651,596
Derivative liabilities, marked to market		24,784,406
Asset retirement obligations		14,538,550
Amount attributable to liabilities assumed	$	40,974,552
Net assets acquired	$	403,142,234

Approximately $40.4 million of revenues and $13.6 million of direct operating expenses attributed to the Stronghold Acquisition are included in the Company's Statements of Operations for the period from September 1, 2022 through December 31, 2022.

NOTE 6 – DEPOSIT FORFEITURE INCOME

In the second quarter of 2020, the Company entered into an agreement with an intended buyer to sell the Company's Delaware Basin 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 its Statements of Operations as no divestiture of assets had occurred. Refer to "Note 17 - LEGAL MATTERS" for further details.

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:

Net Capitalized Costs

As of December 31,	2022	2021
Oil and natural gas properties, full cost method	$ 1,463,838,595	$ 883,844,745
Financing lease asset subject to depreciation	3,019,476	1,422,487
Fixed assets subject to depreciation	3,147,125	2,089,722
Total Properties and Equipment	1,470,005,196	887,356,954
Accumulated depletion, depreciation and amortization	(289,935,259)	(235,997,307)
Net Properties and Equipment	$ 1,180,069,937	$ 651,359,647

Net Costs Incurred in Oil and Gas Producing Activities

For the years Ended December 31,	2022	2021
Payments for the Stronghold Acquisition	$ 177,823,787	$ —
Payments to purchase oil and natural gas properties	1,563,703	1,368,437
Proceeds from divestiture of oil and natural gas properties	(23,700)	(2,000,000)
Payments to develop oil and natural gas properties	129,332,155	51,302,131
Payments to acquire or improve fixed assets subject to depreciation	319,945	568,832
Sale of fixed assets subject to depreciation	$ (134,600)	$ —
Total Net Costs Incurred	$ 308,881,290	$ 51,239,400

NOTE 8 – DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to fluctuations in crude oil and natural gas prices on its production. It utilizes 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 has historically used either costless collars, deferred premium puts, or swaps for this purpose. Oil derivative contracts are based on WTI Crude Oil prices and natural gas contacts are based on Henry Hub or Waha 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 deferred premium put contract has the premium established upon entering the contract, and due upon settlement of the contract.

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 derivative contracts have been with lenders under our credit facility. Non-performance risk is incorporated in the discount rate by adding the quoted bank (counterparty) credit default swap (CDS) rates to the risk free rate. Beginning September 1, the Company assumed the derivative liabilities (novated hedges) associated with its acquisition of the Stronghold assets (see "Note 5 - ACQUISITIONS & DIVESTITURES"), which are subject to master netting agreements. Additional derivative contracts with the same counterparty are also subject to netting. Still, in accordance with ASC 815-10-50-4B, the Company continues to classify the fair value of all its derivative positions on a gross basis in its corresponding Balance Sheets.

The Company’s derivative financial instruments are recorded at fair value and included as either assets or liabilities in the accompanying Balance Sheets. The Company has not designated its derivative instruments as hedges for accounting purposes, and, as a result, 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 (Expense)" under the heading "Gain (loss) on derivative contracts" in the accompanying Statements of Operations.

The following presents the impact of the Company’s contracts on its balance sheets for the periods indicated.

	As of December 31,	
	2022	2021
Commodity derivative instruments, marked to market:		
Derivative assets, current	16,193,327	—
Discounted deferred premiums	(11,524,165)	—
Derivatives assets, current, net of premiums	**$ 4,669,162**	**$ —**
Derivative assets, noncurrent	7,606,258	—
Discounted deferred premiums	(1,476,848)	—
Derivative assets, noncurrent, net of premiums	**$ 6,129,410**	**$ —**
Derivative liabilities, current	**$ 13,345,619**	**$ 29,241,558**
Derivative liabilities, noncurrent	**$ 10,485,650**	**$ —**

The components of “Gain (loss) on derivative contracts” are as follows for the respective periods:

	For the years ended December 31,		
	2022	2021	2020
Oil derivatives:			
Realized gain (loss) on oil derivatives	$ (61,875,870)	$ (53,511,332)	$ 22,522,591
Unrealized gain (loss) on oil derivatives	40,546,123	(24,143,120)	(2,164,779)
Gain (loss) on oil derivatives	$ (21,329,747)	$ (77,654,452)	$ 20,357,812
Natural gas derivatives:			
Realized gain (loss) on natural gas derivatives	(650,084)	743,178	—
Unrealized gain (loss) on natural gas derivatives	447,172	(941,867)	1,008,256
Gain (loss) on natural gas derivatives	$ (202,912)	$ (198,689)	$ 1,008,256
Gain (loss) on derivative contracts	$ (21,532,659)	$ (77,853,141)	$ 21,366,068

The components of “Cash (paid) received for derivative settlements, net” are as follows for the respective periods:

	For the years ended December 31,		
	2022	2021	2020
Cash flows from operating activities			
Cash (paid) received on oil derivatives	$ (61,875,870)	$ (53,511,332)	$ 22,522,591
Cash (paid) received on natural gas derivatives	(650,084)	743,178	—
Cash (paid) received from derivative settlements	$ (62,525,954)	$ (52,768,154)	$ 22,522,591

The following tables reflect the details of current derivative contracts as of December 31, 2022 (Quantities are in barrels (Bbl) for the oil derivative contracts and in million British thermal units (MMBtu) for the natural gas derivative contracts.):

	Oil Hedges (WTI)	
	2023	2024
Swaps:		
Hedged volume (Bbl)	389,250	894,000
Weighted average swap price	$ 77.55	$ 66.94
Deferred premium puts:		
Hedged volume (Bbl)	773,500	91,000
Weighted average strike price	$ 90.64	$ 83.75
Weighted average deferred premium price	$ 15.25	$ 17.32
Two-way collars:		
Hedged volume (Bbl)	487,622	475,350
Weighted average put price	$ 52.16	$ 67.88
Weighted average call price	$ 62.94	$ 83.32
Three-way collars:		
Hedged volume (Bbl)	66,061	—
Weighted average first put price	$ 45.00	$ —
Weighted average second put price	$ 55.00	$ —
Weighted average call price	$ 80.05	$ —

	Gas Hedges (Henry Hub)	
	2023	2024
NYMEX Swaps:		
Hedged volume (MMBtu)	159,890	552,000
Weighted average swap price	$ 2.40	$ 4.61
Two-way collars:(1)		
Hedged volume (MMBtu)	2,258,317	1,712,250
Weighted average put price	$ 3.18	$ 4.00
Call hedged volume (MMBtu)	2,140,317	1,712,250
Weighted average call price	$ 4.89	$ 6.29

	Gas Hedges (basis differential)	
	2023	2024
Waha basis swaps:		
Hedged volume (MMBtu)	1,339,685	—
Weighted average swap price	(2)	$ —

(1) The two-way collars for the first quarter of 2023 include 2x1 collars where the put volumes of 236,000 are two times the call volumes of 118,000.

[(2)] The WAHA basis swaps in place for the calendar year of 2023 consist of two derivative contracts, each with a fixed price of the Henry Hub natural gas price less a fixed amount (weighted average of $0.55 per MMBtu).

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.

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 Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments if events or changes in certain circumstances indicate that adjustments may be necessary.

The following table summarizes the valuation of our assets and liabilities that are measured at fair value on a recurring basis (further detail in "Note 8 - DERIVATIVE FINANCIAL INSTRUMENTS").

	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, 2021				
Commodity Derivatives - Liabilities	$ —	$ (29,241,588)	$ —	$ (29,241,588)
Total	$ —	$ (29,241,588)	$ —	$ (29,241,588)
As of December 31, 2022				
Commodity Derivatives - Assets	$ —	$ 10,798,572	$ —	$ 10,798,572
Commodity Derivatives - Liabilities	$ —	$ (23,831,269)	$ —	$ (23,831,269)
Total	$ —	$ (13,032,697)	$ —	$ (13,032,697)

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.

NOTE 10 – REVOLVING LINE OF CREDIT

On July 1, 2014, the Company entered into a Credit Agreement with SunTrust Bank (now Truist), as lender, issuing bank and administrative agent for several banks and other financial institutions and lenders (the “Administrative Agent”), (which was amended several times) that provided for a maximum borrowing base of $1 billion with security consisting of substantially all of the assets of the Company. In April 2019, the Company amended and restated the Credit Agreement with the Administrative Agent (as amended and restated, the “Credit Facility”).

On August 31, 2022, the Company modified its Credit Facility through a Second Amended and Restated Credit Agreement, extending the maturity date of the facility to August 2026. In conjunction with the Stronghold Acquisition, with the newly acquired assets put up for collateral, the Company established a borrowing base of $600 million. The borrowing base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The borrowing base is redetermined semi-annually on each May 1 and November 1. The borrowing base is subject to reduction 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 syndicate was modified to add five lenders, replacing five exiting lenders. Rather than Eurodollar loans, the reference rate on the Second Amended and Restated Credit Agreement is the Standard Overnight Financing Rate (“SOFR”). Beginning on the June 30, 2023 financial statements and compliance certification delivery date, the Second Amended and Restated Credit Agreement will allow for the Company to declare dividends for its equity owners, subject to certain limitations. These limitations include (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio, as defined in the Second Amended and Restated Credit Agreement, does not exceed 2.00 to 1.00, (iii) the amount of such payments does not exceed Available Free Cash Flow, (iv) the Borrowing Base Utilization Percentage is not greater than 80%, and (v) a Responsible Officer certifies that the other four conditions are satisfied.

The interest rate on each SOFR Loan will be the adjusted term SOFR for the applicable interest period plus a margin between 3.0% and 4.0% (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 Second Amended and Restated Credit Agreement) plus 0.5% per annum, (iii) the adjusted term SOFR 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 2.0% and 3.0% per annum (depending on the then-current level of borrowing base usage).

The Second Amended and Restated Credit Agreement 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, exploration expenses, and all other non-cash charges acceptable to the Administrative Agent) of not more than 3.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Second Amended and Restated Credit Agreement) of 1.0 to 1.0.

The Company is required to maintain on a rolling 24 months basis, hedging transactions in respect of crude oil and natural gas, on not less than 50% of the projected production from its proved, developed, producing oil and gas. If the borrowing base utilization is less than 25% at the hedge testing date and the leverage ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall be 0% from such hedge testing date to the next succeeding hedge testing date. If the borrowing base utilization percentage is equal to or greater than 25%, but less than 50% and the leverage ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall be 25% from such hedge testing date to the next succeeding hedge testing date.

The Second Amended and Restated Credit Agreement also contains other customary affirmative and negative covenants and events of default. As of December 31, 2022, $415,000,000 was outstanding on the Credit Facility. The Company is in compliance with all covenants contained in the Second Amended and Restated Credit Agreement as of December 31, 2022.

Under the Second Amended and Restated Credit Agreement, the applicable percentage for the unused commitment fee is 0.5% per annum for all levels of borrowing base utilization. As of December 31, 2022, the Company's unused line of credit was $184,239,562, representative of a borrowing base of $600 million less the outstanding balance of $415 million, and standby letters of credit of $760,438 in total ($260,000 with state and federal agencies and $500,438 with an insurance company for New Mexico surety bonds). Note 15 - COMMITMENTS AND CONTINGENT LIABILITIES describes changes in the surety bonds which did not affect the letters of credit (collateral) aforementioned.

NOTE 11 – ASSET RETIREMENT OBLIGATION

A reconciliation of the asset retirement obligation for the years ended December 31, 2022, 2021 and 2020 is as follows:

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
Liabilities acquired		662,705
Liabilities incurred		171,390
Liabilities sold		(2,934,126)
Liabilities settled		(904,514)
Revision of estimate (1)		435,419
Accretion expense		744,045
Balance, December 31, 2021	$	15,292,054
Liabilities acquired		14,538,550
Liabilities incurred		353,008
Liabilities settled		(940,738)
Accretion expense		983,432
Balance, December 31, 2022	$	30,226,306

(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 2020 revision of estimates reflect an adjustment to the estimates for plugging costs. The 2021 revision of estimates primarily reflect updated interests for our working interest partners.

NOTE 12 – STOCKHOLDERS' EQUITY

The Company is authorized to issue 225,000,000 shares of common stock, with a par value of $0.001 per share, and 50,000,000 shares of preferred stock with a par value per share of $0.001 per share.

Issuance of equity instruments in public and private offerings – In October 2020, the Company closed on an underwritten public offering of (i) 9,575,800 shares of common stock, (ii) 13,428,500 Pre-Funded Warrants and (iii) 23,004,300 warrants to purchase common stock (the "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 shares of common stock, (ii) 3,300,000 Pre-Funded Warrants and (iii) 6,800,000 Common Warrants at a combined purchase price of $0.70 per share of common stock and Pre-Funded Warrants. 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 for the Common Warrants exercised in 2020 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. In January 2021, the remaining 13,428,500 Pre-Funded Warrants were exercised. During the year ended December 31, 2021, 442,600 of the Common Warrants were exercised. Accordingly, the number of Common Warrants outstanding as of December 31, 2021 was 29,361,700. During the year ended December 31, 2022, a total of 10,253,907 Common Warrants were exercised, leaving the Common Warrants outstanding as of December 31, 2022 to be 19,107,793.

Common stock returned from property acquisition – As part of the Wishbone asset acquisition in April 2019, the Company issued 4,576,951 shares of common stock. In April 2020, 16,702 shares of common stock 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 Stronghold acquisition - As part of the Stronghold Acquisition, 21,339,986 shares of common stock were issued to the sellers. Also as part of the Stronghold Acquisition, 153,176 shares of Preferred Stock were issued to the sellers. Each share of Preferred Stock was automatically convertible into 277.7778 shares of common stock upon stockholder approval of the conversion. On October 27, 2022, the Company's stockholders approved the issuance of, 42,548,892 shares of common stock upon conversion of the 153,176 shares of our Preferred Stock. The preferred shares were automatically converted into such common shares as of October 27, 2022. Refer to "Note 5 - ACQUISITIONS & DIVESTITURES" for the purchase price consideration allocated to the aforementioned stock issuances.

Common stock issued for option exercises – During the year ended December 31, 2022 and 2021, the Company issued a net of 52,494 and 100,000 shares of common stock as a result of stock option exercises, respectively. No stock options were exercised in 2020. The following tables present the details of the exercises:

	Options exercised	Exercise price ($)	Shares issued	Shares retained	Cash paid at exercise ($)	Stock price on date of exercise ($)	Aggregate value of shares retained ($)
2021	100,000	$ 2.00	100,000	—	$ 200,000	$ 3.14	$ —
2021 Totals	100,000		100,000	—	$ 200,000		—
2021 Weighted Averages		$ 2.00				$ 3.14	

	Options exercised	Exercise price ($)	Shares issued	Shares retained	Cash paid at exercise ($)	Stock price on date of exercise ($)	Aggregate value of shares retained ($)
2022	100,000	$ 2.00	52,494	47,506	$ —	$ 4.21	$ 200,000
2022 Totals	100,000		52,494	47,506	$ —		200,000
2022 Weighted Averages		$ 2.00				$ 4.21	

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 "Board") of the Company, the Company accelerated the vesting of 1,131,955 shares of restricted stock and as a result of such acceleration, 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, 2022, 2021, and 2020 was $7,162,231, $2,418,323, and $5,364,162, respectively. These amounts are included in general and administrative expense in the Statements of Operations.

In 2011, the Board approved and adopted a long-term incentive plan (the "2011 Plan"), which was subsequently approved and amended by the shareholders. There were 341,755 shares eligible for grant, either as stock options or as restricted stock, as of December 31, 2022.

In 2021, the Board approved and adopted the Ring Energy, Inc. 2021 Omnibus Incentive Plan (the "2021 Plan"), which was subsequently approved and amended by the shareholders at the 2021 Annual Meeting. There were 5,591,224 shares eligible for grant, either as stock options or as restricted stock, as of December 31, 2022.

Employee Stock Options – No stock options have been granted in the years ended December 31, 2022, 2021, or 2020. All outstanding stock option awards 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, 2022, 2021, and 2020 and changes during the years ended December 31, 2022, 2021, and 2020 is as follows:

	2022		2021		2020	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	365,500	$ 3.61	465,500	$ 3.26	2,748,500	$ 6.28
Issued	—	—	—	—	—	—
Forfeited or rescinded	—	—	—	—	(2,283,000)	6.89
Exercised	(100,000)	2.00	(100,000)	2.00	—	—
Outstanding at end of year	265,500	$ 4.21	365,500	$ 3.61	465,500	$ 3.26
Exercisable at end of year	265,500	$ 4.21	365,500	$ 3.61	455,300	$ 3.11

For the years ended December 31, 2022, 2021, and 2020 the Company incurred share-based compensation expense related to stock options of $—, $20,934, and $927,559, respectively. As of December 31, 2022, the Company had $0 of unrecognized compensation cost related to stock options. The aggregate intrinsic value of options vested and expected to vest as of December 31, 2022 was $89,700. The aggregate intrinsic value of options exercisable at December 31, 2022 was $89,700. The year-end intrinsic values are based on a December 31, 2022 closing stock price of $2.46.

Stock options exercised of 100,000 shares in 2022 had an aggregate intrinsic value on the date of exercise of $221,000. Stock options exercised of 100,000 shares in 2021 had an aggregate intrinsic value on the date of exercise of $114,000. No stock options were exercised in 2020.

The following table summarizes information related to the Company's stock options outstanding as of December 31, 2022:

	Options Outstanding		
Exercise price	Number Outstanding	Weighted-Average Remaining Contractual Life (in years)	Number Exercisable
$ 2.00	195,000	1.00	195,000
5.50	5,000	1.21	5,000
14.54	10,000	2.74	10,000
8.00	4,500	2.92	4,500
6.42	15,000	3.34	15,000
11.75	36,000	3.95	36,000
	265,500	1.63	265,500

Restricted stock grants – Following is a table reflecting the restricted stock grants during 2022, 2021 and 2020:

Grant date	# of shares of restricted stock
October 1, 2020	900,000
October 26, 2020	150,000
December 15, 2020	930,000
April 30, 2021	33,950
June 17, 2021	1,162,152
July 6, 2021	11,824
July 12, 2021	4,007
September 1, 2021	10,417
September 8, 2021	3,306
February 9, 2022	1,247,061
April 13, 2022	7,143
May 10, 2022	10,349
June 16, 2022	2,150
July 14, 2022	8,547
August 29, 2022	30,581
September 1, 2022	37,797
September 19, 2022	49,645

Restricted stock grants issued prior to 2020 vest at the rate of 20% each year over five years beginning one year from the date granted. Restricted stock grants issued during 2020 and in following years vest at a rate of 33% each year over three years beginning one year from the date granted for all employees; for members of the Board, the restricted stock grants vest on the earliest of (i) the day before the next shareholder meeting or (ii) the first anniversary of the date of the award. A summary of the status of restricted stock grants and changes during the years ended December 31, 2022, 2021 and 2020 is as follows:

	2022		2021		2020	
	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 year	2,572,596	$ 1.75	2,132,297	$ 2.94	1,341,889	$ 4.99
Granted	1,393,273	2.83	1,225,656	2.77	1,980,000	0.71
Forfeited or rescinded	(31,185)	2.83	0	—	(9,200)	3.97
Vested	(1,310,894)	1.79	(785,357)	1.37	(1,180,392)	4.97
Outstanding at end of year	2,623,790	$ 2.29	2,572,596	$ 1.75	2,132,297	$ 2.94

For the years ended December 31, 2022, 2021 and 2020, the Company incurred share-based compensation expense related to restricted stock grants of $4,148,639, $2,225,895, and $4,436,603, respectively. As of December 31, 2022, the Company had $2,457,386 of unrecognized compensation cost related to restricted stock grants that will be recognized over a weighted average period of 1.78 years.

During 2022, 2021, and 2020, 1,310,894, 785,357, and 1,180,392 shares of restricted stock vested, respectively. At the dates of vesting those shares had an aggregate intrinsic value of $3,807,996, $2,049,603, and $801,133, respectively.

Performance Stock Units - In accordance with the 2021 Plan, as of November 22, 2021, the Company entered into performance stock unit ("PSU") agreements (the "PSU Agreement") with certain employees. Upon approval the Board, a total of 860,216 PSU were granted to the Company's five executive officers (the "2021 PSU Awards"). The performance period for the 2021 PSU Awards began on January 1, 2021, and will end December 31, 2023, with such awards vesting on the last day of the performance period (the vesting date). The PSUs are performance-based restricted stock units subject to the terms of the 2021 Plan and the PSU Agreement. On February 9, 2022, the Company granted additional PSU awards. A total of 860,216 PSU awards were granted to the Company's five executive officers (the "2022 PSU Awards"). The performance period for the 2022 PSU Awards began on January 1, 2022, and will end on December 31, 2024, with such awards vesting on the last day of the performance period (the vesting date). The PSUs are performance-based restricted stock units subject to the terms of the 2021 Plan and the PSU Agreement.

A summary of the status of the performance stock grants as of December 31, 2022 and 2021 along with changes during the year ended December 31, 2022 and 2021 are as follows:

	2022		2021	
	Performance Stock Units	Weighted-Average Grant Date Fair Value	Performance Stock Units	Weighted-Average Grant Date Fair Value
Outstanding at beginning of year	860,216	$ 3.87	—	$ —
Granted	860,216	3.65	860,216	3.87
Forfeited or rescinded	—	—	—	—
Vested	—	—	—	—
Outstanding at end of year	1,720,432	$ 3.76	860,216	$ 3.87

For the year ended December 31, 2022 and 2021, the Company incurred share-based compensation expense related to the PSU Awards of $3,013,592 and $171,494, respectively. As of December 31, 2022, the Company had $4,037,141 of unrecognized compensation cost related to the PSU Awards that will be recognized over a weighted average period of 1.56 years.

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, 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, 2022, 2021, and 2020:

	2022	2021	2020
Employer safe harbor match	284,094	228,273	138,997

NOTE 14 – RELATED PARTY TRANSACTIONS

The Company leased office space in Tulsa, Oklahoma, from Arenaco, LLC ("Arenaco"), a company that is owned by two stockholders of the Company, Mr. Rochford, former Chairman of the Board, and Mr. McCabe, a former director of the Company. During the years ended December 31, 2021 and 2020, the Company paid $10,000 and $60,000 respectively, to Arenaco. The month-to-month Arenaco lease was terminated as of March 31, 2021.

During June 2021, the Company began using Pro-Ject Chemicals, LLC ("PJ Chemicals") to perform various chemical services on its wells. As publicly disclosed on the Company's website, Paul D. McKinney, Chief Executive Officer and Chairman of the Board, was a member of the board of directors of Pro-Ject Holdings, LLC, a privately owned oil field chemical services company and parent of PJ Chemicals. Mr. McKinney owned 0.34% of the shares of Pro-Ject Holdings, LLC. During the year ended December 31, 2021, the Company paid $117,830 to PJ Chemicals. As of December 31, 2021 the Company had accounts payable of $37,641 due to PJ Chemicals. As of 2022, Mr. McKinney is no longer on the board of directors of Pro-Ject Holdings, LLC.

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 is related to inactive wells and will remain in place until the Company returns those wells to activity or plugs them. One of those wells has been plugged, and the bond released in the amount of $50,150, leaving the amount related to inactive wells as $50,288. On December 23, 2022, the Company increased its blanket plugging surety bond by $200,000. As of December 31, 2022, the Company had surety bonds in total of $650,288.

NOTE 16 – INCOME TAXES

For the years ended December 31, 2022, 2021, and 2020, components of our provision for (benefit from) income taxes are as follows:

Provision for Income Taxes	2022	2021	2020
Federal deferred tax	$ 6,437,680	$ —	$ (6,001,176)
State deferred tax	1,971,044	90,342	—
Provision for (Benefit From) Income Taxes	$ 8,408,724	$ 90,342	$ (6,001,176)

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

Rate Reconciliation	2022	2021	2020
Pre-tax book income (loss)	$ 147,043,749	$ 3,413,234	$ (259,413,004)
Tax at federal statutory rate	$ 30,879,187	$ 716,779	$ (54,476,731)
Excess tax benefit from stock option exercises and restricted stock vesting	(312,268)	(175,187)	(1,109,379)
Adjust prior estimates to tax return	214,740	2,938,948	(1,930,994)
States taxes, net of federal benefit	1,443,145	430,654	(964,393)
Valuation allowance	(24,151,242)	(3,827,194)	52,161,412
Non-deductible expenses and other	335,162	6,342	318,909
Provision for (Benefit From) Income Taxes	$ 8,408,724	$ 90,342	$ (6,001,176)

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. The net deferred taxes consisted of the following as of December 31, 2022 and 2021:

	12/31/2022 Total	12/31/2021 Total
Deferred Tax Assets		
Net operating loss (NOL) carryforward	70,564,004	60,155,112
Equity compensation	1,554,680	691,076
Asset retirement obligation	6,635,099	3,348,875
Fair market value of derivatives	2,827,202	6,403,745
§163(j) business interest expense carryforward	4,917,358	—
Others	1,173,441	61,077
Gross Deferred Tax Assets	87,671,784	70,659,885
Less: valuation allowance	(24,182,975)	(48,334,217)
Net Deferred Tax Assets	63,488,809	22,325,668
Deferred Tax Liabilities		
Property and equipment	(71,402,820)	(22,415,959)
Other	(585,005)	—
Net Deferred Liabilities	(71,987,825)	(22,415,959)
Net Deferred Tax Liabilities	(8,499,016)	(90,292)

As of December 31, 2022, the Company had net operating loss carryforwards for federal income tax reporting purposes of approximately $109.3 million which, if unused, will begin to expire in 2027 and fully expire in 2037 and an additional $225.1 million that can be carried forward indefinitely. The shares issued for the Stronghold Acquisition (further discussed in Note 5 - "ACQUISITIONS & DIVESTITURES) resulted in the Company having an ownership change under Section 382 of the Internal Revenue Code of 1986, as amended. Section 382 limits the availability of certain tax attributes, including net operating losses and disallowed interest carryforwards, to offset future taxable income of the Company. In evaluating its need for a valuation allowance against its deferred tax assets, the Company has estimated the amount of tax attributes related to the pre-ownership change period to be available under Section 382 in periods in which it expects deferred tax liabilities to be realized based on currently available information. Based on its current analysis, the Company does not anticipate any material tax attributes to expire unused as result of the Section 382 ownership change; however, the ultimate timing in the amount of tax attributes available in future periods may be different than the Company's current estimate and will be determined in each year as new information becomes available. Changes in expectation in the timing of the availability of the Company's tax attributes could result in adjustments to the valuation allowance in future years as it updates its analysis based on new information.

As of December 31, 2022, we carried a valuation allowance against our federal and state deferred tax assets of $24,182,975. We have considered both the positive and negative evidence in determining whether it was more likely than not that some portion or all of our deferred tax assets will be realized. The amount of deferred tax assets considered realizable could, however, be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence is no longer present and additional weight is given to subjective positive evidence, including projections for growth. During 2022, the Company determined that certain existing deferred tax assets will not be offset by existing deferred tax liabilities as a result of the 80% limitation on the utilization of net operating losses incurred after 2017. This results in an ending federal net deferred tax liability after valuation allowance of $6,437,680. Additionally, the Company reported a net state deferred tax liability at December 31, 2022 of $2,061,336 attributable to certain state deferred tax liabilities mainly associated with property and equipment.

NOTE 17 – LEGAL MATTERS

The Company is a defendant in a lawsuit in Harris County District Court, Houston, Texas, styled EPUS Permian Assets, LLC, v. Ring Energy, Inc., that was filed in July 2021. The plaintiff, EPUS Permian Assets, LLC, claims breach of contract, money had and received by fraudulent inducement, unjust enrichment and constructive trust. The plaintiff is requesting its forfeited deposit of $5,500,000 in connection with a proposed property sale by the Company plus related damages, and attorneys' fees and costs. The action relates to a proposed property sale by the Company to the plaintiff, which was extended by the Company on several occasions with the plaintiff ultimately failing to perform on the agreement and the Company keeping the deposit. The Company believes that the claims by the plaintiff are entirely without merit and is conducting a vigorous defense and counterclaim. The Company has filed an answer and a counterclaim denying the allegations and asserting affirmative defenses that would bar or substantially limit the plaintiff's claims, asserting breach of contract and requesting a declaratory judgment and attorneys' fees and costs. The parties have taken depositions and are conducting discovery.

NOTE 18 – SUBSEQUENT EVENTS

Stronghold acquisition - On February 28, 2023, as discussed in "Note 5 - ACQUISITIONS & DIVESTITURES," the deferred cash consideration of $15.0 million in cash was paid to Stronghold in accordance with terms set forth in the Purchase Agreement for the Stronghold Acquisition. In addition on March 1, 2023, the holdback amount of approximately $8.3 million which was held in escrow in accordance with the terms set forth in the Purchase Agreement for the Stronghold Acquisition was distributed to Stronghold.

Common stock issued pursuant to warrant exercise - On February 2, 2023, the Company issued 2,517,427 shares of common stock pursuant to the exercise of Common Warrants with an exercise price of $0.80. Gross and net proceeds were $2,013,942. On March 1, 2023, the Company issued 2,000,000 shares of common stock pursuant to the exercise of Common Warrants with an exercise price of $0.80. Gross and net proceeds were $1,600,000.

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 derivatives, and other financing expense.

For the years ended December 31,		2022		2021		2020
Oil, natural gas, and natural gas liquids sales	$	347,249,537	$	196,305,966	$	113,025,138
Lease operating expenses		(47,695,351)		(30,312,399)		(29,753,413)
Gathering, transportation and processing costs		(1,830,024)		(4,333,232)		(4,090,238)
Ad valorem taxes		(4,670,617)		(2,276,463)		(3,125,222)
Production taxes		(17,125,982)		(9,123,420)		(5,228,090)
Depreciation, depletion, and amortization		(55,740,767)		(37,167,967)		(43,010,660)
Ceiling test impairment		—		—		(277,501,943)
General and administrative (exclusive of corporate overhead)		(1,617,095)		(2,003,876)		(1,454,041)
Results of Oil, Natural Gas, and Natural Gas Liquids Producing Operations	$	218,569,701	$	111,088,609	$	(251,138,469)

Net Costs Incurred in Oil and Gas Producing Activities

For the years Ended December 31,		2022		2021
Payments for the Stronghold Acquisition	$	177,823,787	$	—
Payments to purchase oil and natural gas properties		1,563,703		1,368,437
Payments to develop oil and natural gas properties		129,332,155		51,302,131
Payments to acquire or improve fixed assets subject to depreciation		319,945		568,832
Sale of fixed assets subject to depreciation		(134,600)		—
Proceeds from divestiture of oil and natural gas properties		(23,700)		(2,000,000)
Total Net Costs Incurred	$	308,881,290	$	51,239,400

Net Capitalized Costs

As of December 31,		2022		2021
Oil and natural gas properties, full cost method	$	1,463,838,595	$	883,844,745
Financing lease asset subject to depreciation		3,019,476		1,422,487
Fixed assets subject to depreciation		3,147,125		2,089,722
Total Properties and Equipment		1,470,005,196		887,356,954
Accumulated depletion, depreciation and amortization		(289,935,259)		(235,997,307)
Net Properties and Equipment	$	1,180,069,937	$	651,359,647

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.

The proved reserves estimates shown herein for the years ended December 31, 2022, 2021 and 2020 have been prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

The reserve information in these Financial Statements represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the Company's control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. As a result, estimates by different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the Company's proved reserves will decline as reserves are produced.

The oil prices as of December 31, 2022, 2021 and 2020 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate ("WTI") spot prices which equates to $90.15 per barrel, $63.04 per barrel and $36.04 per barrel, respectively. The natural gas prices as of December 31, 2022, 2021 and 2020 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $6.358 per MMBtu, $3.598 per MMBtu and $1.99 per MMBtu, respectively. Prices are adjusted by local field and lease level differentials and are held constant for life of reserves in accordance with SEC guidelines.

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.

For the Year Ended December 31,	2022		
	Oil (1)	**Natural Gas (1)**	**Natural Gas Liquids (1)**
Proved Developed and Undeveloped Reserves			
Beginning of year	65,838,609	71,773,789	—
Purchases of minerals in place	28,086,920	108,456,107	16,715,626
Extensions, discoveries and improved recovery	628,978	522,178	52,810
Sale of minerals in place	—	—	—
Production	(3,459,477)	(4,088,642)	(371,337)
Revisions of previous quantity estimates	(2,390,287)	(18,792,983)	6,708,559
End of year	88,704,743	157,870,449	23,105,658
Proved Developed at beginning of year	36,820,824	39,748,880	—
Proved Undeveloped at beginning of year	29,017,785	32,024,909	—
Proved Developed at end of year	57,012,137	106,399,050	15,332,804
Proved Undeveloped at end of year	31,692,606	51,471,399	7,772,854

For the Year Ended December 31,	2021		
	Oil (1)	**Natural Gas (1)**	**Natural Gas Liquids (1)**
Proved Developed and Undeveloped Reserves			
Beginning of year	66,264,286	61,305,027	—
Purchases of minerals in place	2,180,497	824,512	—
Extensions, discoveries and improved recovery	3,975,675	5,172,392	—
Sale of minerals in place	(462,970)	(555,879)	—
Production	(2,686,940)	(2,535,188)	—
Revisions of previous quantity estimates	(3,431,939)	7,562,925	—
End of year	65,838,609	71,773,789	—
Proved Developed at beginning of year	38,260,638	34,335,520	—
Proved Undeveloped at beginning of year	28,003,648	26,969,507	—
Proved Developed at end of year	36,820,824	39,748,880	—
Proved Undeveloped at end of year	29,017,785	32,024,909	—

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

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During the year ended December 31, 2022, our extensions and discoveries of 769 MBoe (one thousand Boe) resulted primarily from the 2022 operated drilling program in the Northwest Shelf and Central Basin Platform as well as non-operated activity in the Northwest Shelf. Revisions of 1,186 MBoe were predominately the result of converting from two-stream to three-stream reserves, the removal of proved undeveloped reserves in our Delaware asset, well performance, increased cost from 2022 industry activity, and increased commodity pricing.

The increase in proved undeveloped reserves was primarily attributable to the Stronghold Acquisition.

Standardized Measure of Discounted Future Net Cash Flows – 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.

Standardized Measure of Discounted Future Net Cash Flows

December 31,	2022	2021	2020
Future cash inflows	$ 9,871,961,000	$ 4,853,709,000	$ 2,682,488,655
Future production costs	(2,751,896,250)	(1,395,437,250)	(821,515,126)
Future development costs	(647,196,750)	(347,757,000)	(244,323,270)
Future income taxes	(1,142,147,641)	(501,586,949)	(208,645,934)
Future net cash flows	5,330,720,359	2,608,927,801	1,408,004,325
10% annual discount for estimated timing of cash flows	(3,058,606,841)	(1,471,562,953)	(852,133,072)
Standardized Measure of Discounted Future Net Cash Flows	$ 2,272,113,518	$ 1,137,364,848	$ 555,871,253

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the three-year period ended December 31, 2022:

Changes in Standardized Measure of Discounted Future Net Cash Flows

	2022	2021	2020
Beginning of the year	$ 1,137,364,848	$ 555,871,253	$ 923,175,051
Purchase of minerals in place	996,313,882	33,688,718	—
Extensions, discoveries and improved recovery	20,447,842	79,003,885	61,303,074
Development costs incurred during the year	67,454,522	17,513,180	29,916,746
Sales of oil and gas produced, net of production costs	(283,588,498)	(154,615,685)	(70,634,853)
Sales of minerals in place	—	(2,523,746)	—
Accretion of discount	133,209,763	63,810,764	92,838,323
Net changes in price and production costs	646,819,172	636,884,944	(368,974,767)
Net change in estimated future development costs	(53,253,626)	(44,357,751)	(3,883,985)
Revisions of previous quantity estimates	33,583,837	(22,259,508)	(66,213,586)
Changes in estimated timing of cash flows	(119,428,019)	86,845,188	(139,039,115)
Net change in income taxes	(306,810,205)	(112,496,394)	97,384,365
End of the Year	$ 2,272,113,518	$ 1,137,364,848	$ 555,871,253

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, 2022, December 31, 2021, and December 31, 2020, in Ring Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2022, to references to our report dated February 3, 2023, 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, 2022 (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, 2022. 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. 333-229515, 333-230966 and 333-237988) and Form S-8 (Nos. 333-191485 and 333-257633).

Very truly yours,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

Fort Worth, Texas
March 9, 2023

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 9, 2023, with respect to the financial statements and internal control over financial reporting included in the Annual Report of Ring Energy, Inc. on Form 10-K for the year ended December 31, 2022. We consent to the incorporation by reference of said reports in the Registration Statements of Ring Energy, Inc. on Forms S-3 (File No. 333-229515, File No. 333-230966, File No. 333-237988 and File No. 333-267599) and Forms S-8 (File No. 333-191485 and File No. 333-257633).

/s/ GRANT THORNTON LLP

Houston, Texas
March 9, 2023

EideBailly

CPAs & BUSINESS ADVISORS

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The statements of operations, stockholders' equity and cash flows for the year ended December 31, 2020 of Ring Energy, Inc. (the "financial statements"), included in Part IV of the Form 10-K for the fiscal year ended December 31, 2022, have been audited by Eide Bailly LLP, independent auditors, as stated in our report appearing herein.

We consent to the inclusion in the Form 10-K for the fiscal year ended December 31, 2022 of our report, dated March 16, 2021, on our audit of the financial statements of Ring Energy, Inc.

Eide Bailly LLP

Denver, Colorado
March 9, 2023

Exhibit 31.1

CERTIFICATIONS

I, Paul D. McKinney, certify that:

1. I have reviewed this annual report on Form 10-K 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 9, 2023

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

Exhibit 31.2

CERTIFICATIONS

I, Travis T. Thomas, certify that:

1. I have reviewed this annual report on Form 10-K 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 9, 2023

/s/ Travis T. Thomas
Travis T. Thomas, 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 on Form 10-K of Ring Energy, Inc. (the “Company”) for the year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned chief executive officer and 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 9, 2023

/s/ Paul D. McKinney
Paul D. McKinney
Chief Executive Officer
(Principal Executive Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

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 on Form 10-K of Ring Energy, Inc. (the "Company") for the year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned chief financial officer and 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 9, 2023

/s/ Travis T. Thomas
Travis T. Thomas
Chief Financial Officer
(Principal Financial Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

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 3, 2023

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, 2023

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, 2023. It is our understanding that the proved reserve estimates shown herein constitute 100 percent of all proved reserves owned by Ring Energy, Inc. ("Ring Energy"). This report, completed on February 3, 2023, has been prepared for use in filings with the Securities and Exchange Commission ("SEC") by Ring Energy. 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	48,274.8	8,737.3	31,692.6	88,704.7
Gas	-- MMcf	72,295.8	34,103.3	51,471.4	157,870.5
NGL	-- Mbbl	10,673.6	4,659.2	7,772.9	23,105.7
Revenue					
Oil/Condensate	-- M$	4,639,803.5	838,643.9	3,044,362.3	8,522,809.0
Gas	-- M$	304,763.7	153,528.3	222,115.6	680,407.6
NGL	-- M$	315,837.6	130,209.9	222,694.8	668,742.2
Severance and Ad Valorem Taxes	-- M$	345,146.7	74,016.2	226,159.7	645,322.6
Operating Expenses	-- M$	1,191,150.4	360,100.6	555,321.1	2,106,572.0
Investments	-- M$	67,412.9	117,240.0	462,543.8	647,196.8
Operating Income (BFIT)	-- M$	3,656,695.5	571,025.4	2,245,148.3	6,472,867.5
Discounted @ 10%	-- M$	**1,669,008.1**	**237,674.3**	**866,974.6**	**2,773,656.5**

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 $6.358 per MMBtu of gas (Henry Hub spot) and $90.15 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 2022. 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 $96.08 per barrel of oil and $4.31 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 costs to plug and abandon all wells have been considered. For the PDP and PDNP reserves, a net cost of $48,152,062 is modelled in sixteen cases scheduled over the next 50 years. The PUD cases have an average gross cost of $44,000 scheduled at the economic limit for each well.

The proved reserves classifications conform to criteria of the SEC as defined in pages 2-3 of the Appendix. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the 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.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. This evaluation was supervised by J. Zane Meekins, Executive Vice President at Cawley, Gillespie & Associates, Inc. and a Registered Professional Engineer in the State of Texas (License No. 71055). Cawley, Gillespie & Associates, Inc. is independent with respect to Ring Energy as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

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

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method, which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is a common approach used for "resource plays," where an abundance of wells with similar production profiles facilitates the reliable estimation of future reserves with a relatively high degree of accuracy. The analogy method may also be applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained in this manner are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

APPENDIX

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

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

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

"(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

"(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

"(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

"(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

"(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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

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

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

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

"(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

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

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

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

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

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