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

FORM 10-K

(Mark One)

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

For the fiscal year ended SEPTEMBER 30, 2021

OR

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

Commission File Number 001-31759

PHX MINERALS INC.
(Exact name of Registrant as specified in its Charter)

OKLAHOMA	**73-1055775**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
Valliance Bank Tower, Suite 1100, 1601 NW Expressway Oklahoma City, OK	**73118**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (405) 948-1560

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Common Stock, $0.01666 par value	PHX	New York Stock Exchange

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant, computed by using the $2.87 per share closing price of registrant's Class A Common Stock, as reported by the New York Stock Exchange at March 31, 2021, was $63,165,371.

The number of shares of Registrant's Class A Common Stock outstanding as of December 10, 2021, was 32,970,819.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of PHX Minerals Inc. (to be filed no later than 120 days after September 30, 2021) relating to the Annual Meeting of Shareholders to be held on March 1, 2022, are incorporated into Part III of this Form 10-K.

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Special Note Regarding Forward Looking Statements

This Annual Report on Form 10-K for the year ended September 30, 2021 (this “Annual Report on Form 10-K”, this “Annual Report” or this “Form 10-K”) includes “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”). These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements in this Form 10-K by words such as “anticipate,” “project,” “intend,” “estimate,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “plan,” “forecast,” “target” or similar expressions.

All statements, other than statements of historical facts, included in this Annual Report on Form 10-K that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements. Forward-looking statements may include, but are not limited to statements relating to: our ability to execute our business strategies; the volatility of realized natural gas and oil prices; the level of production on our properties; estimates of quantities of natural gas, oil and NGL reserves and their values; general economic or industry conditions; legislation or regulatory requirements; conditions of the securities markets; our ability to raise capital; changes in accounting principles, policies or guidelines; financial or political instability; acts of war or terrorism; title defects in the properties in which we invest; and other economic, competitive, governmental, regulatory or technical factors affecting our properties, operations or prices.

We caution you that the forward-looking statements contained in this Form 10-K are subject to risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, the risks described in Item 1A of this Annual Report on Form 10-K, and all quarterly reports on Form 10-Q filed subsequently thereto.

Should one or more of the risks or uncertainties described above or elsewhere in this Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. Any forward-looking statement speaks only as of the date of which such statement is made, and we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Except as required by applicable law, all forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Glossary of Certain Terms

The following is a glossary of certain accounting, natural gas and oil industry and other defined terms used in this Annual Report:

ASC	Accounting Standards Codification.
ASU	Accounting Standards Update.
Bcf	Billion cubic feet.
Bcfe	Natural gas stated on a Bcf basis and crude oil and natural gas liquids converted to a billion cubic feet of natural gas equivalent by using the ratio of one million Bbl of crude oil or natural gas liquids to six Bcf of natural gas.
Bbl	Barrel.
Board	Board of directors of the Company.
BTU	British Thermal Units.
Common Stock	The Company's Class A Common Stock.
completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas and/or crude oil.
conventional	An area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.
DD&A	Depreciation, depletion and amortization.
developed acreage	The number of acres allocated or assignable to productive wells or wells capable of production.
development well	A well drilled within the proved area of a natural gas or crude oil reservoir to the depth of a stratigraphic horizon known to be productive.
dry hole	Exploratory or development well that does not produce natural gas and/or crude oil in economically producible quantities.
EBITDA	Earnings before interest, taxes, depreciation and amortization (including impairment). This is a Non-GAAP measure.
ESOP	The PHX Minerals Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan.
exploratory well	A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or crude oil in another reservoir.
FASB	The Financial Accounting Standards Board.
field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
formation	A layer of rock, which has distinct characteristics that differ from nearby rock.
G&A	General and administrative costs.
GAAP	United States generally accepted accounting principles.
gross acres or gross wells	The total acres or wells in which an interest is owned.
held by production or HBP	An oil and gas lease continued into effect into its secondary term for so long as a producing gas and/or oil well is located on any portion of the leased premises or lands pooled therewith.
horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.
hydraulic fracturing	A process involving the high-pressure injection of water, sand and additives into rock formations to stimulate natural gas and crude oil production.
Independent Consulting Petroleum Engineer(s)	DeGolyer and MacNaughton of Dallas, Texas.
LOE	Lease operating expense.
Mcf	Thousand cubic feet.
Mcfd	Thousand cubic feet per day.
Mcfe	Natural gas stated on an Mcf basis and crude oil and natural gas liquids converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil or natural gas liquids to six Mcf of natural gas.
Mcfed	Natural gas stated on an Mcf basis and crude oil and natural gas liquids converted to a thousand cubic feet of natural gas equivalent by using the ratio of one Bbl of crude oil or natural gas liquids to six Mcf of natural gas per day.
Mmbtu	Million BTU.
Mmcf	Million cubic feet.
Mmcfe	Natural gas stated on an Mmcf basis and crude oil and natural gas liquids converted to a million cubic feet of natural gas equivalent by using the ratio of one thousand Bbl of crude oil or natural gas liquids to six Mmcf of natural gas.

minerals, mineral acres or mineral interests	Fee mineral acreage owned in perpetuity by the Company.
net acres or net wells	The sum of the fractional interests owned in gross acres or gross wells.
NGL	Natural gas liquids.
NRI	Net revenue interest.
NYMEX	New York Mercantile Exchange.
OPEC	Organization of Petroleum Exporting Countries.
overriding royalty interest	An interest in the natural gas and oil produced under a lease, or the proceeds from the sale thereof, apportioned out of the working interest, to be received free and clear of all costs of development, operation or maintenance.
PDP	Proved developed producing.
play	Term applied to identified areas with potential natural gas and/or oil reserves.
production or produced	Volumes of natural gas, oil and NGL that have been both produced and sold.
proved reserves	The quantities of natural gas and crude oil, 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 renewal is reasonably certain.
proved developed reserves	Reserves expected to be recovered through existing wells with existing equipment and operating methods.
proved undeveloped reserves or PUD	Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
PV-10	Estimated pre-tax present value of future net revenues discounted at 10% using SEC rules.
royalty interest	Well interests in which the Company does not pay a share of the costs to drill, complete and operate a well, but receives a smaller proportionate share (as compared to a working interest) of production.
SEC	The United States Securities and Exchange Commission.
unconventional	An area believed to be capable of producing natural gas and crude oil occurring in accumulations that are regionally extensive, but may lack readily apparent traps, seals and discrete hydrocarbon water boundaries that typically define conventional reservoirs. These areas tend to have low permeability and may be closely associated with source rock, as is the case with gas and oil shale, tight oil and gas sands, and coalbed methane, and generally require horizontal drilling, fracture stimulation treatments or other special recovery processes in order to achieve economic production.
undeveloped acreage	Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and/or crude oil.
working interest	Well interests in which the Company pays a share of the costs to drill, complete and operate a well and receives a proportionate share of production.
WTI	West Texas Intermediate.

As used herein, the “Company,” “PHX,” “we,” “us” and “our” refer to PHX Minerals Inc., formerly known as Panhandle Oil and Gas Inc., and its predecessors and subsidiaries unless the context requires otherwise.

Fiscal year references

All references to years or fiscal years in this Annual Report, unless otherwise noted, refer to the Company’s fiscal year ended September 30. For example, references to 2021 mean the fiscal year ended September 30, 2021.

References to natural gas and oil properties

References to natural gas and oil properties inherently include NGL associated with such properties.

PART I

ITEM 1. Business

Overview

PHX Minerals Inc. was founded in Range, Texas County, Oklahoma, in 1926, as Panhandle Cooperative Royalty Company. The Company operated as a cooperative until 1979, when it merged into Panhandle Royalty Company and its shares became publicly traded. On April 2, 2007, the Company changed its name to Panhandle Oil and Gas Inc., and on October 8, 2020, the Company changed its name to PHX Minerals Inc.

PHX Minerals Inc. is an Oklahoma City-based company focused on perpetual natural gas and oil mineral ownership in resource plays in the United States. Prior to a strategy change in 2019, the Company participated with a working interest on some of its mineral and leasehold acreage and as a result still holds legacy interests in leasehold acreage and non-operated working interests in natural gas and oil properties.

Strategic Focus on Mineral Ownership

During fiscal year 2019, we made the strategic decision to focus on perpetual natural gas and oil mineral ownership and growth by acquiring minerals in our core areas of focus and by developing our significant mineral acreage inventory. In accordance with this new strategy, we have ceased taking any working interest positions on our mineral and leasehold acreage. During fiscal years 2020 and 2021, we did not participate with a working interest in the drilling of any new wells. We believe that our strategy to focus on mineral ownership is the best path forward to provide our shareholders the greatest risk-weighted returns on their investments.

A “mineral fee” is an interest in real property in which the owner owns all of the rights to the minerals under the surface forever, as compared to a mineral lease in which the lessee’s rights end at the expiration of the lease term or after production in paying quantities ceases with respect to the lease or the lease otherwise terminates in accordance with its terms. Generally, the mineral interest owner of a mineral fee interest reserves a non-cost bearing royalty interest upon the lease of such gas, oil, and other minerals to a gas and oil exploration and development company. Such companies lease such mineral interests from the fee mineral owner for a term with the expectation of producing natural gas and oil, thereby generating free cash flow from bonuses and royalties to the mineral interest owner.

As referenced above, our leasehold interests, rather than our mineral interests, are non-operated working interests. These non-operated working interests require us to contribute our proportionate share of the costs incurred by the operator in the development of such minerals. As discussed above and further below, since the end of 2019 and going forward, we no longer seek to participate with such working interests and have started a process of divesting working interests and redeploying the proceeds into high quality mineral and royalty properties. Our producing mineral and leasehold properties are located primarily in Oklahoma, Texas, Louisiana, North Dakota and Arkansas.

Although a significant amount of our revenues is currently derived from the production and sale of natural gas, oil and NGL from our working interests, a growing portion of our revenues is derived from lease bonus payments and royalties generated from the production and sale of natural gas, oil and NGL. These royalties are tied to our perpetual ownership of mineral acreage, unless we sell such mineral interests. Royalties are due and payable whenever the operator of such interest produces and sells natural gas, oil or NGL from wells located on our mineral acreage.

As of September 30, 2021, we owned approximately 251,600 perpetual mineral acres, as detailed in the table below:

Play	Net Acres	% Producing	% Leased But Not Producing	% Unleased
SCOOP	6,837	63%	7%	30%
STACK	5,814	89%	5%	6%
Haynesville	1,318	100%	0%	0%
Bakken/Three Forks	3,106	89%	0%	11%
Arkoma Stack	11,576	64%	2%	34%
Permian	35,931	8%	17%	75%
Fayetteville	9,871	72%	0%	28%
Other	177,147	19%	3%	78%
Total:	**251,600**	**25%**	**5%**	**70%**

Approximately 30% of our net minerals are currently under lease with an operator and 25% have a producing well. Additionally, 70% of our net mineral position is currently unleased, providing the opportunity, through potential future leases, to generate additional cash flow from bonus payments and royalties without spending additional capital. We also own working interests, royalty interests or both, in 6,457 producing natural gas and oil wells and 277 wells in the process of being drilled or completed.

Exploration and development of our natural gas and oil properties are conducted by natural gas and oil exploration and production companies, which typically are larger, independent oil and gas operating companies. We do not operate any natural gas and oil properties. While we previously were an active working interest participant in wells drilled on our mineral and leasehold acreage, we now focus on growth through mineral acquisitions and through development of our significant mineral acreage inventory.

We intend to maximize shareholder value through the acquisition of mineral acreage in the core areas of resource plays with substantial undeveloped opportunities, divestiture of non-core minerals with limited optionality when the amount negotiated exceeds our projected total value, and proactive leasing of our mineral holdings.

Our Business Strategy

Our principal business objective is to maximize shareholder value. At the end of 2019, we made the strategic decision to cease taking working interest positions on our mineral and leasehold acreage. Our focus since then has been on growth through mineral acquisitions and by developing our significant mineral acreage inventory in our core areas. We believe this is the best path to provide our shareholders the greatest risk-weighted returns on their investment. We intend to accomplish this objective by executing the following corporate strategies:

- ***Actively Manage Mineral and Leasehold Assets as a Portfolio to Maximize Value.*** We plan to manage our mineral and leasehold assets through the following:
    - Increasing our mineral fee holdings by acquiring mineral acreage in the core areas of natural gas and oil resource plays with substantial undeveloped opportunities that meet or exceed our minimum return threshold;
    - Utilizing in-house geology and engineering expertise as a competitive advantage;
    - Proactively leasing our unleased mineral holdings; and
    - High-grading our asset base by: (a) selectively divesting non-core minerals when anticipated sales price exceeds our projected total value, (b) optimizing our leasehold and working interest positions through strategic sales and farmouts of such assets, and (c) redeploying proceeds from sales into our core areas.
- ***Maintain a Stable and Well Capitalized Balance Sheet.*** We plan to maintain a strong financial position through the following:
    - Maintaining a conservative amount of debt outstanding to ensure our ability to successfully operate in all business and commodity environments; and
    - Hedging our future natural gas and oil prices to manage commodity price risk and protect our cash flow.

Our Business Strengths

We believe the following attributes position us to achieve our objectives:

- ***Focusing on Perpetual Mineral Fee Ownership.*** Our strategic decision to focus on mineral ownership provides us with the perpetual option to benefit from future development and technology. We are focused on generating meaningful revenues through lease bonuses and royalty interests, and our royalty revenue as a percentage of total revenue continues to increase. As of September 30, 2021, we owned approximately 251,600 net mineral acres located primarily in Oklahoma, Texas, North Dakota, Louisiana and Arkansas. We also own working interests, royalty interests, or both, in 6,457 producing natural gas and oil wells and 277 wells in the process of being drilled or completed.

- ***Mineral and Leasehold Ownership in Multiple Top-Tier Resource Plays.*** We own mineral and leasehold interests in multiple top-tier resource plays in the United States, including positions in the SCOOP, STACK, Haynesville, Bakken/Three Forks, Arkoma Woodford, Eagle Ford, Permian Basin and Fayetteville plays. A significant portion of our revenues is derived from the production and sale of natural gas, oil and NGL from these positions. During fiscal year 2021, production on our acreage averaged 24,864 Mcfed with approximately 74%, 15% and 11% of such volumes derived from the production of natural gas, oil and NGL, respectively.

- ***Material Undeveloped Mineral Position in Gas and Oil Producing Basins.*** Over 70% of our mineral fee position is currently unleased or not currently producing, providing us with the opportunity to generate additional cash flows from bonus payments and royalties without deploying additional capital. We have an active program in place focused on leasing open acreage to generate additional lease bonus revenue and future royalty revenue.

- ***Stable and Flexible Financial Position.*** We maintain a stable and flexible financial position by actively managing our debt, cash and working capital. We hedge to manage commodity price risk and to protect our balance sheet and cash flow.

- ***Experienced Management and Technical Team.*** We have a management and technical team with extensive experience in the oil and gas industry. Our management and technical team members average over 20 years of industry experience in each applicable area of the Company, including accounting, land, geology, engineering and mergers and acquisitions.

Principal Products and Markets

We derive our revenue through bonus and royalty payments and from working interests on our mineral and leasehold acreage. Our principal products from the production associated with our royalty and non-operated interests, in order of revenue generated, are natural gas, crude oil and NGL. These products are generally sold by well operators to various purchasers, including pipeline and marketing companies, which service the areas where the producing wells are located. Since we do not operate any of the wells in which we own an interest, we must rely on the operating expertise of numerous companies that operate the wells in which we own interests, including expertise in the drilling and completion of new wells, producing well operations and, in most cases, the marketing or purchasing of production from the wells. We receive payment from natural gas, oil and NGL sales from the well operator or the contracted purchaser.

Prices of natural gas, oil and NGL are dependent on numerous factors beyond our control, including supply and demand, competition, weather, international events and geo-political circumstances, actions taken by OPEC and economic, political and regulatory developments. Since demand for natural gas is subject to weather conditions, prices received for our natural gas production may be subject to seasonal variations.

We enter into price risk management financial instruments (derivatives) to reduce our exposure to short-term fluctuations in the price of natural gas and oil and to protect our return on investments. The derivative contracts apply only to a portion of our natural gas and oil production, provide only partial price protection against declines in natural gas and oil prices and may limit the benefit of future increases in natural gas and oil prices. Please see Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding the derivative contracts we enter into.

Competitive Business Conditions

The oil and natural gas industry is highly competitive, particularly with respect to attempting to acquire additional fee mineral interests and natural gas, oil and NGL reserves. Many factors beyond our control affect our competitive position. Some of these factors include: the quantity and price of foreign oil imports; domestic supply and deliverability of natural gas, oil and NGL;

changes in prices received for natural gas, oil and NGL production; business and consumer demand for refined natural gas, oil products and NGL; and the effects of federal, state and local regulation of the exploration for, production of and sales of natural gas, oil and NGL (see Item 1A – "Risk Factors"). Many companies have substantially greater resources than we have, and such companies may have more resources to evaluate, bid for and purchase more mineral fee, royalty and similar interests than our financial or human resources permit.

We do not operate any of the wells in which we have an interest; rather, we rely on operating companies with greater resources, staff, equipment, research and experience for both drilling and production of gas and oil wells. Our business strategy is to use our stable and flexible financial position, coupled with our own geologic and economic evaluations, to acquire new mineral acreage and to lease or farmout our mineral and leasehold acreage interests. We believe this strategy allows us to compete effectively in a competitive mineral market; however, our ability to acquire additional mineral fee, royalty and similar interests in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Major Customers

Our natural gas, oil and NGL production is sold, in most cases, through our lessees or well operators to numerous different purchasers. The loss of certain major purchasers of natural gas, oil and NGL production could have a material adverse effect on our ability to produce and sell, through our lessees or well operators, natural gas, oil and NGL production. The following table shows sales to major purchasers, by percentage, through various operators/purchasers during 2021, 2020 and 2019.

	2021	2020	2019
Company A	14%	23%	23%
Company B	7%	6%	8%
Company C	0%	5%	8%

Regulation of the Natural Gas and Oil Industry

General

As the owner of mineral fee interests and non-operating working interests, we do not have any employees or contractors actually operating in the field, and we are not directly subject to many of the regulations of the oil and gas industry. The following disclosure describes regulations and environmental matters more directly associated with operators of natural gas and oil properties, including our current operators. Since we do not operate any wells in which we have interests, actual compliance with many laws and regulations is controlled by the well operators, and we are responsible only for our proportionate share of the costs, if any, involved on wells in which we own a working interest.

Natural gas and oil operations are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. Legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for potential revision. Some of these requirements carry substantial penalties for failure to comply.

Although we are generally not directly subject to many of the rules, regulations and limitations impacting the natural gas and oil exploration and production industry as a whole, companies that operate our interests may be impacted by such rules and regulations and we may be responsible for our proportionate share of costs for wells on which we own a working interest. While we may be partially insulated from compliance costs applicable to our operator-lessees, we may still be indirectly impacted by operator regulations because our revenue stream depends on operators complying with applicable laws and regulations that govern the production of natural gas, oil and NGL.

Regulation of Drilling and Production

The production of natural gas and oil is subject to regulation under federal, state and local statutes, rules, orders and regulations. These statutes and regulations require that operators obtain permits for drilling operations and drilling bonds, as well as provide for reporting requirements concerning operations. Additionally, the state regulatory agencies where we own mineral and leasehold interests have enacted regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing and plugging and abandonment of wells. The effect of these regulations is to limit the amount of natural gas and oil that can be produced from wells and to limit the number of wells or the locations which can be drilled. Additionally, some states where we hold mineral or leasehold interests may impose a production or severance tax with respect to the production and sale of natural gas, oil and NGL within the applicable jurisdictions.

Regulation of Transportation of Oil

The sale and transportation of our crude oil is generally undertaken by the operators (or by third parties at the direction of the operators) of our properties. Sales of crude oil, condensate and NGL are not currently regulated and are made at negotiated prices; however, Congress has enacted price controls in the past and could reenact price controls in the future.

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 (the "FERC") regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. 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.

Regulation of Transportation and Sale of Natural Gas

The sale and transportation of our natural gas is generally undertaken by the operators (or by third parties at the direction of the operators) of our properties. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government 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.

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.

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.

Environmental Compliance and Risks

Our operators and properties are impacted by extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment and relating to safety and health.

Natural gas and oil 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. Historically, most of the environmental regulation of gas and oil production has been left to state regulatory boards or agencies in those jurisdictions where there is significant natural gas and oil production, with limited direct regulation by such federal agencies as the Environmental Protection Agency (the "EPA"). However, there are various regulations issued by the EPA and other governmental agencies that would govern significant spills, blow-outs or uncontrolled emissions.

Many states, including states where we own properties, have enacted natural gas and oil regulations that apply to the drilling, completion and operations of wells and the disposal of waste oil and salt water. The operators of our properties are subject to such regulations. 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: The Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as "CERCLA" or

"Superfund"; the Oil Pollution Act of 1990; the Resource Conservation and Recovery Act, also known as "RCRA"; the Clean Air Act; Federal Water Pollution Control Act of 1972, or the Clean Water Act; and the Safe Drinking Water Act of 1974.

Since we do not operate any wells in which we own an interest, actual compliance with environmental laws is controlled by the well operators, and we are only responsible for our proportionate share of the costs for wells in which we own a working interest. As such, we have no knowledge of any instances of non-compliance with existing laws and regulations. We maintain insurance coverage at levels customary in the industry, but we are not fully insured against all environmental risks.

Taxes

Our natural gas and oil properties are subject to various taxes, such as gross production taxes and, in some cases, ad valorem taxes, which we pay on minerals we own.

Employees

At September 30, 2021, we had 20 full-time employees, including our executive officers, and did not have any part-time employees.

Executive Officers

Chad L. Stephens has served as our President and Chief Executive Officer since January 2020. Mr. Stephens served as Interim CEO from October 2019 to December 2019, and he has served as a Director of the Company since September 2017. Prior to joining the Company, Mr. Stephens held several positions at Range Resources Corporation from 1990 through his retirement in 2018, where he served as Senior Vice President – Corporate Development.

Ralph D'Amico has served as our Chief Financial Officer and Corporate Secretary since March 2020 and as Vice President – Business Development since January 2019. Prior to joining the Company, Mr. D'Amico served as a Managing Director at Seaport Global Securities and held various energy investment banking positions at Stifel Nicolaus, Jefferies, Friedman Billings Ramsey and Salomon Smith Barney prior to then.

Corporate Office

Our offices are located at Valliance Bank Tower, Suite 1100, 1601 NW Expressway, Oklahoma City, OK 73118. Our telephone number is (405) 948-1560 and our website is **www.phxmin.com**.

Available Information

We make available free of charge on our website (www.phxmin.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other filings pursuant to Section 13(a) or 15(d) of the Exchange Act, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC.

We also make available within the "Corporate Governance" section under the "Investors" section of our website our Code of Ethics & Business Practices, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines, and Audit Committee, Governance and Nominating Committee and Compensation Committee Charters, each of which have been approved by our Board of Directors. We will make timely disclosure on our website of any change to, or waiver from, the Code of Ethics & Business Practices and Code of Ethics for Senior Financial Officers for our principal executive and senior financial officers. Copies of our Code of Ethics & Business Practices and Code of Ethics for Senior Financial Officers are available free of charge by writing us at: PHX Minerals Inc., Attn: Chad True, 1601 NW Expressway, Suite 1100, Oklahoma City, OK 73118.

ITEM 1A. Risk Factors

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. If any of the following risk factors should occur, our financial condition could be materially impacted, and the holders of our securities could lose part or all of their investment in the Company. As the owner of mineral fee interests and non-operating working interests, we do not operate any natural gas and oil properties, and we do not have any employees or contractors in the field. As such, the risks associated with natural gas and oil operations only affect us indirectly and typically through our non-operating working interests as we proportionately share in the costs of operating such wells. The risk factors described below are not exhaustive, and investors are encouraged to perform their own investigation with respect to our Company and our business. Investors should also read the other information in this Form 10-K, including the financial statements and related notes.

Risks Related to our Business

The volatility of natural gas and oil prices due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.

The supply of and demand for natural gas, oil and NGL impact the prices we realize on the sale of these commodities and, in turn, materially affect our financial results. Our revenues, operating results, cash available for distribution and the carrying value of our natural gas and oil properties depend significantly upon the prevailing prices for natural gas, oil and NGL. Natural gas, oil and NGL prices have historically been, and will likely continue to be, volatile. The prices for natural gas, oil and NGL are subject to wide fluctuation in response to a number of factors beyond our control, including:

- domestic and worldwide economic conditions;
- economic, political, regulatory and tax developments;
- market uncertainty;
- changes in the supply of and demand for natural gas, oil and NGL, both domestically and abroad;
- the impacts and effects of public health crises, pandemics and epidemics, such as the ongoing COVID-19 pandemic;
- availability and capacity of necessary transportation and processing facilities;
- commodity futures trading;
- regional price differentials;
- differing quality of oil produced (i.e., sweet crude versus heavy or sour crude);
- differing quality and NGL content of natural gas produced;
- conservation and environmental protection efforts;
- the level of imports and exports of natural gas, oil and NGL;
- political instability or armed conflicts in major natural gas and oil producing regions;
- actions taken by OPEC or other major natural gas, oil and NGL producing or consuming countries;
- technological advancements affecting energy consumption and energy supply;
- the level of prices and expectations about future prices of natural gas and oil;
- the level of global natural gas and oil exploration and production;
- the cost of exploring for, developing, producing and delivering natural gas and oil;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia;
- the ability of members of OPEC to agree to and maintain oil price and production controls;

- speculative trading in natural gas and crude oil derivative contracts;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- the price and availability of, and competition from, alternative fuels;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;
- the proximity, cost, availability and capacity of natural gas and oil pipelines and other transportation facilities; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty. If the prices of natural gas, oil and NGL decline, our operations, financial condition and level of expenditures for the development of our natural gas, oil and NGL reserves may be materially and adversely affected. Lower natural gas, oil and NGL prices may also result in a reduction in the borrowing base under our credit agreement, which may be determined at the discretion of our lenders.

Low natural gas, oil and NGL prices for a prolonged period of time would have a material adverse effect on the Company.

The volatility of the energy markets makes it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty. Though more stable than during fiscal year 2020, natural gas, oil and NGL prices continued to fluctuate in fiscal year 2021, with the ongoing COVID-19 pandemic contributing to volatility and uncertainty. Our financial position, results of operations, access to capital and the quantities of natural gas, oil and NGL that may be economically produced would be negatively impacted if natural gas, oil and NGL prices were low for an extended period of time. The ways in which low prices could have a material negative effect include the following:

- significantly decrease the number of wells operators drill on our acreage, thereby reducing our production and cash flows;
- cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves and maintain or increase production;
- future undiscounted and discounted net cash flows from producing properties would decrease, possibly resulting in recognition of impairment expense;
- certain reserves may no longer be economic to produce, leading to lower proved reserves, production and cash flow;
- access to sources of capital, such as equity and debt markets, could be severely limited or unavailable; and
- we may incur a reduction in the borrowing base on our credit facility.

The ongoing COVID-19 pandemic may adversely affect our business, financial condition and results of operations.

The ongoing COVID-19 pandemic ("COVID-19") has created significant uncertainty and economic disruption, as well as heightened volatility in the prices of oil and natural gas. The negative impact on worldwide demand for oil and natural gas resulting from COVID-19 led to a precipitous decline in oil prices, further exacerbated by the early March 2020 failure by OPEC+ to reach an agreement over proposed oil production cuts and global storage considerations. Although OPEC+ subsequently agreed to cut oil production, crude oil prices remained depressed as a result of an increasingly utilized global storage network and the decrease in crude oil demand due to COVID-19. Since then, oil and natural gas prices have risen, but such prices are expected to continue to be volatile as a result of COVID-19 and related measures taken by governments around the world, and as changes in oil and natural gas inventories, oil demand and economic performance are reported. The response to COVID-19 continues to evolve, and the ultimate impact of this pandemic is highly uncertain and subject to change. The extent of the impact of COVID-19 on our operational and financial performance will depend on future developments, including the duration of the pandemic, COVID-19 variants, the pandemic's severity, actions to contain the disease or mitigate its impact and the effectiveness of treatments and vaccines, all of which are highly uncertain and cannot be predicted with certainty at this time. Declines in oil prices due to COVID-19 could result in the events discussed in the immediately preceding risk factor, which could have a material adverse effect on our business and financial results. We are unable to predict the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments, including the pandemic's ongoing effect on the demand for oil and natural gas and the response of the overall economy and the financial markets after the pandemic and response measures come to an end, the timing of which remains highly uncertain.

Lower natural gas, oil and NGL prices or negative adjustments to natural gas, oil and NGL reserves may result in significant impairment charges.

We have elected to utilize the successful efforts method of accounting for our natural gas and oil exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and development dry holes are capitalized and amortized by property using the unit-of-production method (the ratio of natural gas, oil and NGL volumes produced to total proved or proved developed reserves) as natural gas, oil and NGL are produced.

All long-lived assets, principally our natural gas and oil properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset on our books may be greater than our future net cash flows. The need to test a property for impairment may result from declines in natural gas, oil and NGL sales prices or unfavorable adjustments to natural gas, oil and NGL reserves. The decision to not participate in future development on our leasehold acreage can trigger a test for impairment. Also, once assets are classified as held for sale, they are reviewed for impairment. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded. If an impairment charge is recognized, cash flow from operating activities is not impacted, but net income and, consequently, shareholders' equity are reduced. In periods when impairment charges are incurred, it could have a material adverse effect on our results of operations. See Note 11 to the financial statements included in Item 8 – "Financial Statements and Supplemental Data" for further discussion on impairment under the heading "Impairment."

Our future success depends on finding, developing or acquiring additional reserves, and failure to find or acquire additional reserves will cause reserves and production to decline materially from their current levels.

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Our proved reserves will decline materially as reserves are produced except to the extent that we acquire additional properties containing proved reserves, conduct additional successful exploration and development drilling, successfully apply new technologies or identify additional behind-pipe zones (different productive zones within existing producing well bores) or secondary recovery reserves.

Drilling for natural gas and oil invariably involves unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient reserves to return a profit after deducting drilling, completion, operating and other costs. In addition, wells that are profitable may not achieve a targeted rate of return. We rely on third-party operators' interpretation of seismic data and other advanced technologies in identifying prospects and in conducting exploration and development activities. Nevertheless, prior to drilling a well, the seismic data and other technologies used do not allow operators to know conclusively whether natural gas, oil or NGL is present in commercial quantities.

Cost factors can adversely affect the economics of any project, and the eventual cost of drilling, completing and operating a well is controlled by well operators and existing market conditions. Further, drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts and surface cratering;

- lack of availability to market production via pipelines or other transportation;
- adverse weather conditions;
- environmental hazards or liabilities;
- lack of water disposal facilities;
- governmental regulations;
- cost and availability of drilling rigs, equipment and services; and
- expected sales price to be received for natural gas, oil or NGL produced from the wells.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently hold properties, which could result in unforeseen operating difficulties. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to effectively integrate the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition, results of operations and cash available for distribution. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our growth, results of operations and cash available for distribution.

Any acquisitions of additional mineral and royalty interests that we complete will be subject to substantial risks.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, prices, revenues, capital expenditures, operating expenses and costs;
- a decrease in our liquidity by using a significant portion of our cash generated from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- mistaken assumptions about the overall cost of equity or debt;
- our ability to obtain satisfactory title to the assets we acquire;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; and
- the occurrence of other significant changes, such as impairment of natural gas and oil properties, goodwill or other intangible assets, asset devaluation or restructuring charges.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of natural gas, oil and NGL with precision. Natural gas, oil and NGL reserve engineering requires subjective estimates of underground accumulations of natural gas, oil and NGL using assumptions concerning future prices of these commodities, future production levels and operating and development costs. In estimating our reserves, we and our Independent Consulting Petroleum Engineering Firm (DeGolyer and MacNaughton of Dallas, Texas) must make various assumptions with respect to many matters that may prove to be incorrect, including:

- future natural gas, oil and NGL prices;
- unexpected complications from offset well development;
- production rates;
- reservoir pressures, decline rates, drainage areas and reservoir limits;
- interpretation of subsurface conditions including geological and geophysical data;
- potential for water encroachment or mechanical failures;
- levels and timing of capital expenditures, lease operating expenses, production taxes and income taxes, and availability of funds for such expenditures; and
- effects of government regulation.

If any of these assumptions prove to be incorrect, our estimates of reserves, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly.

Our standardized measure of oil and natural gas reserves is calculated using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month individual product prices for each month within the 12-month period prior to September 30. These prices and the operating costs in effect as of the date of estimation are held flat over the life of the properties. Production and income tax expenses are deducted from this calculation of future estimated development, with the result discounted at 10% per annum to reflect the timing of future net revenue in accordance with the rules and regulations of the SEC. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates made for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy records. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures. Further, our lack of knowledge of all individual well information known to the well operators such as incomplete well stimulation efforts, restricted production rates for various reasons and up-to-date well production data, etc. may cause differences in our reserve estimates.

Because PUD reserves, under SEC reporting rules, may only be recorded if the wells they relate to are scheduled to be drilled within five years of the date of recording, the removal of PUD reserves that are not developed within this five-year period may be required. Removals of this nature may significantly reduce the quantity and present value of our natural gas, oil and NGL reserves. Please read Item 2 – "Properties – Proved Reserves" and Note 16 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data."

Since forward-looking prices and costs are not used to estimate discounted future net cash flows from our estimated proved reserves, the standardized measure of our estimated proved reserves is not necessarily the same as the current market value of our estimated proved natural gas, oil and NGL reserves.

The timing of the development and production on our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating discounted future net cash flows, in compliance with the FASB statement on oil and natural gas producing activities disclosures, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company, or the oil and natural gas industry in general.

Debt level and interest rates may adversely affect our business.

On September 1, 2021, we entered into a four-year Credit Agreement (the "Credit Agreement") with certain lenders and Independent Bank, as Administrative Agent and Letter of Credit Issuer (as defined in the Credit Agreement). The Credit Agreement replaced our prior revolving credit facility set forth in the Amended and Restated Credit Agreement dated as of November 25, 2013, as amended, among the Company, each lender party thereto, and BOKF, NA dba Bank of Oklahoma, as administrative agent, which we repaid in full and terminated. As of September 30, 2021, we had a balance of $17,500,000 drawn on our credit facility set forth in the Credit Agreement (the "Credit Facility). The Credit Facility's initial borrowing base is set at $27,500,000. All obligations under the Credit Agreement are secured, subject to permitted liens and other exceptions, by a first-priority security interest on substantially all of our personal property and at least 80% of the total value of the proved, developed and producing Oil and Gas Properties (as defined in the Credit Agreement) owned by the Company.

Should we incur additional indebtedness under the Credit Facility to fund capital projects or for other reasons, there is a risk this could adversely affect our business operations as follows:

- cash flows from operating activities required to service indebtedness may not be available for other purposes;
- covenants contained in the Credit Agreement may limit our ability to borrow additional funds, pay dividends and make certain investments;
- any limitation on the borrowing of additional funds may affect our ability to fund capital projects and may also affect how we will be able to react to economic and industry changes;
- a significant increase in the interest rate under the Credit Facility will limit funds available for other purposes; and
- changes in prevailing interest rates may affect our capability to meet our interest payments, as the Credit Facility bears interest at floating rates.

The borrowing base of our Credit Facility is subject to periodic redetermination and is based in part on natural gas, oil and NGL prices. A lowering of our borrowing base because of lower natural gas, oil or NGL prices, or for other reasons, could require us to repay indebtedness in excess of the established borrowing base, or we might need to further secure the debt with additional collateral. Our ability to meet any debt obligations depends on our future performance. General business, economic, financial and product pricing conditions, along with other factors, affect our future performance, and many of these factors are beyond our control. In addition, our failure to comply with the restrictive covenants relating to our Credit Facility could result in a default, which might adversely affect our business, financial condition, results of operations and cash flows.

We may incur losses as a result of title defects in the properties we own.

Consistent with industry practice, we do not have current abstracts or title opinions on all of our mineral acreage and, therefore, cannot be certain that we have unencumbered title to all of these properties. Our failure to cure any title defects that may exist may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we may suffer a financial loss.

Competition in the oil and natural gas industry is intense, and most of our competitors have greater financial and other resources than we do.

We compete in the highly competitive areas of natural gas and oil acquisition, development, exploration and production. We face intense competition from both major and independent oil and natural gas companies to acquire desirable producing properties, new properties for future exploration and human resource expertise necessary to effectively develop properties. We also face similar competition in obtaining sufficient capital to maintain or grow production.

We may be subject to information technology system failures, network disruptions, cyber-attacks or other breaches in data security.

The oil and natural gas industry in general has become increasingly dependent upon digital technologies to conduct day-to-day operations, including certain exploration, development and production activities. We use digital technology to estimate quantities of natural gas, oil and NGL reserves, process and record financial data and communicate with our employees and third parties. Power, telecommunication or other system failures due to hardware or software malfunctions, computer viruses, vandalism, terrorism, natural disasters, fire, human error or by other means could significantly affect our ability to conduct our business. Though we have implemented complex network security measures, stringent internal controls and maintain offsite backup of all crucial electronic data, there cannot be absolute assurance that a form of system failure or data security breach will not have a material adverse effect on our financial condition and operations results. For instance, unauthorized access to our reserves information or other proprietary or commercially sensitive information could lead to data corruption, communication interruption or other disruptions in our operations or planned business transactions, any of which could have a material adverse impact on our results of operations. Further, as cyber-attacks 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 vulnerability to cyber-attacks.

Our derivative activities may reduce the cash flow received for natural gas and oil sales.

In order to manage exposure to price volatility on our natural gas and oil production, we currently, and may in the future, enter into natural gas and oil derivative contracts for a portion of our expected production. Natural gas and oil price derivatives may limit the cash flow we actually realize and therefore reduce our ability to fund future projects. None of our natural gas and oil price derivative contracts are designated as hedges for accounting purposes; therefore, all changes in fair value of derivative contracts are reflected in earnings. Accordingly, these fair values may vary significantly from period to period, materially affecting reported earnings. In addition, this type of derivative contract can limit the benefit we would receive from increases in the prices for natural gas and oil. The fair value of our natural gas and oil derivative instruments outstanding as of September 30, 2021, was a net liability of $13,784,467.

There is risk associated with our derivative contracts that involves the possibility that counterparties may be unable to satisfy contractual obligations to us. If any counterparty to our derivative instruments were to default or seek bankruptcy protection, it could subject a larger percentage of our future natural gas and oil production to commodity price changes and could have a negative effect on our ability to fund future acquisitions.

Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 1 and 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding derivative contracts.

We have identified a material weakness in our internal control over financial reporting which could, if not remediated, result in a material misstatement in our financial statements.

The ongoing internal control provisions of Section 404 of the Sarbanes-Oxley Act of 2002 require us to identify material weaknesses in internal control over financial reporting, which is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with GAAP. Our management, including our principal executive officer and principal financial officer, does not expect that our internal controls and disclosure controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud in the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of the Company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting. As disclosed in Part II, Item 9A of this Form 10-K, our management has identified a material weakness in our internal control over financial reporting.

A material weakness is defined as a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. In connection with our management's assessment of our internal control over financial reporting, our management, together with our independent registered public accounting firm, identified the following material weakness in our internal control over financial reporting as of September 30, 2021 related to the review of the annual income tax provision prepared by a third-party firm: our review of the annual income tax provision did not include a process to sufficiently evaluate deferred tax assets to determine if a valuation allowance was necessary. Additionally, the review was not sufficiently detailed to identify a material misstatement in deferred income taxes.

Because of this material weakness, our management concluded that our internal control over financial reporting was not effective as of September 30, 2021, based on criteria set forth by the Committee of Sponsoring Organization of the Treadway Commission in *Internal Control – Integrated Framework (2013)*.

As disclosed in Part II, Item 9A of this Form 10-K, our management has commenced the process of designing a remediation plan to remediate the material weakness described above, although such remediation plan has not yet been designed or implemented. If our remedial measures are insufficient to address the material weakness, or if additional material weaknesses or significant deficiencies in our internal control are discovered or occur in the future, our financial statements may contain material misstatements and we could be required to restate our financial results, which could lead to substantial additional costs for accounting and legal fees.

Any revisions or restatements of our financial statements may lead to a loss of investor confidence and have a negative impact on the trading prices of our securities. Any of these matters could adversely affect our business, reputation, revenues, results of operations and financial condition and limit our ability to access the capital markets through equity or debt issuances.

Future legislative or regulatory changes may result in increased costs and decreased revenues, cash flows and liquidity.

Companies that operate wells in which we own a working interest are subject to extensive federal, state and local regulation. We, as a working interest owner, are therefore indirectly subject to these same regulations. New or changed laws and regulations such as those described below could have a material adverse effect on our business. In particular, changes in law or regulation related to hydraulic fracturing or greenhouse gases could potentially increase capital, compliance and operating costs significantly, as well as halt or delay the further development of oil and gas reserves on our properties.

Federal Income Taxation

We are subject to U.S. federal income tax, as well as income or capital-based taxes in various states, and our operating cash flow is sensitive to the amount of income taxes we must pay. Income taxes are assessed on our revenue after consideration of all allowable deductions and credits. Changes in the types of earnings that are subject to income tax, the types of costs that are considered allowable deductions or the rates assessed on our taxable earnings would all impact our income taxes and resulting operating cash flow.

Certain beneficial provisions within the Tax Cuts and Jobs Act passed in December 2017 are set to be reduced beginning in 2023 and beyond, such as a reduction in the amount of immediate bonus depreciation available for qualified property placed into service.

Additionally, further revisions to U.S. tax law, such as a reversal of the corporate income tax rate reduction, the repeal of the percentage depletion allowance, the repeal of expensing for intangible drilling costs or the repeal of enhanced bonus depreciation, could have a materially adverse effect on our business. Moreover, the U.S. Department of Treasury has broad authority to issue regulations and interpretative guidance that may significantly impact how we apply U.S. tax law, with a corresponding impact on the results of our operations for the periods affected.

Oklahoma Taxation

Oklahoma imposes a gross production tax, or severance tax, on the value of natural gas, oil and NGL produced within the state. Under Oklahoma law, the gross production tax rate on the first three years of a horizontal well's production is 5.2% and 7% thereafter. Future changes to Oklahoma production taxes could affect the profitability of wells producing natural gas, oil and NGL in Oklahoma.

Hydraulic Fracturing and Water Disposal

The vast majority of natural gas and oil wells drilled in recent years have been, and future wells are expected to be, hydraulically fractured as a part of the process of completing the wells and putting them on production. This is true of the wells drilled in which we own an interest. Hydraulic fracturing is a process that involves pumping water, sand and additives at high pressure into rock formations to stimulate natural gas and oil production. In developing plays where hydraulic fracturing, which requires large volumes of water, is necessary for successful development, the demand for water may exceed the supply. A lack of readily available water or a significant increase in the cost of water could cause delays or increased completion costs.

In addition to water, hydraulic fracturing fluid contains chemical additives designed to optimize production. Well operators are being required in certain states to disclose the components of these additives. Additional states and the federal government may follow with similar requirements or may restrict the use of certain additives. This could result in more costly or less effective development of wells.

Once a well has been hydraulically fractured, the fluid produced from the fractured wells must be either treated for reuse or disposed of by injecting the fluid into disposal wells. Injection well disposal processes have been, and continue to be, studied to determine the extent of correlation between injection well disposal and the occurrence of earthquakes. Certain studies have concluded there is a correlation, and this has resulted in the cessation of or the reduction of injection rates in certain water disposal wells, especially in northern Oklahoma.

Efforts to regulate hydraulic fracturing and fluid disposal continue at the local, state and federal level. New regulations are being considered, including limiting water withdrawals and usage, limiting water disposition, restricting which additives may be used, implementing statewide hydraulic fracturing moratoriums and temporary or permanent bans in certain environmentally sensitive areas. Public sentiment against hydraulic fracturing and fluid disposal and shale production could result in more stringent permitting and compliance requirements. Consequences of these actions could potentially increase capital, compliance and operating costs significantly, as well as delay or halt the further development of gas and oil reserves on our properties. Though the Biden administration has not proposed the outright ban of hydraulic fracturing, the administration has proposed significant regulations regarding methane emissions that could potentially affect new and existing wells, including those that are hydraulically fractured. The proposed methane rule is discussed in more detail in the Climate Change section, below.

Any of the above factors could have a material adverse effect on our financial position, results of operations or cash flows.

Climate Change

Certain studies have suggested that emission of certain gases, commonly referred to as “greenhouse gases,” may be impacting the earth’s climate. Methane, the primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas and oil, are examples of greenhouse gases. Various state governments and regional organizations are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as gas and oil production equipment and operations.

Legislation to regulate greenhouse gas emissions has periodically been introduced in the U.S. Congress, and such legislation may be proposed in the future. In addition, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, in preparing an agreement which set greenhouse gas emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the United States in April 2016 and entered into force in November 2016. To help achieve these reductions, federal agencies addressed climate change through a variety of administrative actions. The EPA issued greenhouse gas monitoring and reporting regulations that cover natural gas and oil facilities, among other industries. However, on June 1, 2017, the President of the United States announced that the United States planned to withdraw from the Paris Agreement and to seek negotiations to either reenter the Paris Agreement on different terms or establish a new framework agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which resulted in an exit in November 2020. While the U.S. officially exited the Paris Agreement in November of 2020, the Biden administration immediately rejoined the Paris Agreement after taking office in January of 2021. On January 20, 2021, President Biden signed an executive order triggering a 30-day process to re-enter the agreement.

More recently, the EPA issued a proposed rule to regulate methane emissions from the oil and gas industry. If adopted, states will have authority to incorporate the emission guidelines proposed by EPA or to adopt their own standards that achieve the same degree of emission limitations. The proposed rule applies to the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments. If adopted, these rules would result in additional operating costs, such as costs to purchase and operate emissions controls or lower emitting equipment and costs to implement monitoring requirements.

Seismic Activity

Earthquakes in northern and central Oklahoma and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation that could lead to operational delays, increase operating and compliance costs or otherwise adversely affect operations.

The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on us and our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the CFTC (the United States Commodity Futures Trading Commission) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market including swap clearing and trade execution requirements. New or modified rules, regulations or requirements may increase the cost and availability to the counterparties of our hedging and swap positions which they can make available to us, as applicable, and may further require the counterparties to our derivative instruments to spin off some of their derivative activities to separate entities which may not be as creditworthy as the current counterparties. Any changes in the regulations of swaps may result in certain market participants deciding to curtail or cease their derivative activities.

While many rules and regulations have been promulgated and are already in effect, other rules and regulations remain to be finalized or effectuated and, therefore, the impact of those rules and regulations on us is uncertain at this time. The Dodd-Frank Act, and the rules promulgated thereunder, could (i) significantly increase the cost, or decrease the liquidity, of energy-related derivatives that we use to hedge against commodity price fluctuations (including requirements to post collateral), (ii) materially alter the terms of derivative contracts, (iii) reduce the availability of derivatives to protect against risks we encounter and (iv) increase our exposure to less creditworthy counterparties.

Risks Related to our Third-Party Operators

We cannot control activities on our properties.

We do not operate any of the properties in which we have an interest and have very limited ability to exercise influence over the third-party operators of these properties. Our dependence on the third-party operators of our properties, and on the cooperation of other working interest owners in these properties, could negatively affect the following:

- our return on capital used in drilling or property acquisition;
- our production and reserve growth rates;
- capital required to workover or recomplete wells;
- success and timing of drilling, development and exploitation activities on our properties;
- compliance with environmental, safety and other regulations;
- lease operating expenses; and
- plugging and abandonment costs, including well-site restorations.

Dependency on each operator's judgment, expertise and financial resources could result in unexpected future costs, lost revenues and/or capital restrictions, to the extent they would cumulatively have a material adverse effect on our financial position and results of operations.

The natural gas and oil drilling and producing operations of our third-party operators involve various risks.

Because we do not operate our properties, our business relies heavily upon our third-party operators and their operational effectiveness. Through our third-party operators, we are subject to all the risks normally incident to the operation and development of natural gas and oil properties, including:

- well blowouts, cratering, explosions and human related accidents;
- mechanical, equipment and pipe failures;
- adverse weather conditions, earthquakes and other natural disasters;
- civil disturbances and terrorist activities;
- natural gas, oil and NGL price reductions;
- environmental risks stemming from the use, production, handling and disposal of water, waste materials, hydrocarbons and other substances into the air, soil or water;
- title problems;
- limited availability of financing;
- marketing related infrastructure, transportation and processing limitations; and
- regulatory compliance issues.

As a non-operator, we are also dependent on third-party operators and the contractors they hire for operational safety, environmental safety and compliance with regulations of governmental authorities.

We maintain insurance against many potential losses or liabilities arising from well operations in accordance with customary industry practices and in amounts believed by management to be prudent. However, this insurance does not protect us against all risks. For example, we do not maintain insurance for business interruption, acts of war or terrorism. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant uninsured costs that might have a material adverse effect on our business condition and financial results.

We may experience delays in the payment of royalties and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

A failure on the part of the operators to make royalty payments gives us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a proceeding under title 11 of the United States Code (the "Bankruptcy Code"), in which case our right to enforce or terminate the lease for any defaults, including non-payment, may be substantially delayed or otherwise impaired. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have a substantial period of time to decide whether to ultimately reject or assume the lease, which could prevent the execution of a new lease or the assignment of the existing lease to another operator. In the event that the operator rejected the lease, our ability to collect amounts owed would be substantially delayed, and our ultimate recovery may be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, the replacement operator may not achieve the same levels of production or sell natural gas or oil at the same price as the operator it replaced.

Shortages of oilfield equipment, services, qualified personnel and resulting cost increases could adversely affect results of operations.

The demand for qualified and experienced field personnel, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas, oil and NGL prices, resulting in periodic shortages. When demand for rigs and equipment increases due to an increase in the number of wells being drilled, there have been shortages of drilling rigs, hydraulic fracturing equipment and personnel and other oilfield equipment. Higher natural gas, oil and NGL prices generally stimulate increased demand for, and result in increased prices of, drilling rigs, crews and associated supplies, equipment and services. These shortages or price increases could negatively affect the ability to drill wells and conduct ordinary operations by the operators of our wells, resulting in an adverse effect on our financial condition, cash flow and operating results.

The marketability of natural gas and oil production is dependent upon transportation, pipelines and refining facilities, which neither we nor many of our operators control. Any limitation in the availability of those facilities could interfere with our or our operators' ability to market our or our operators' production and could harm our business.

The marketability of our or our operators' production depends in part on the availability, proximity and capacity of pipelines, tanker trucks and other transportation methods and processing and refining facilities owned by third parties. The amount of oil that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of available capacity on these systems, tanker truck availability and extreme weather conditions. Also, the shipment of our or our operators' natural gas and oil on third-party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we or our operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation, processing or refining-facility capacity could reduce our or our operators' ability to market oil production and have a material adverse effect on our financial condition, results of operations and cash distributions to shareholders. Our or our operators' access to transportation options and the prices we or our operators receive can also be affected by federal and state regulation—including regulation of oil production, transportation and pipeline safety—as well as by general economic conditions and changes in supply and demand. In addition, the third parties on whom we or our operators rely for transportation services are subject to complex federal, state, tribal and local laws that could adversely affect the cost, manner or feasibility of conducting our business.

Risks Related to the Oil and Gas Industry

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, financial condition and cash available for distribution.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit in the European, Asian and U.S. markets contribute to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of natural gas, oil and NGL, volatility in consumer confidence and job markets, may result in an economic slowdown or recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which natural gas, oil and NGL from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and cash available for distribution.

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

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

Risks Related to an Investment in our Common Stock

The issuance of additional shares of our Common Stock could cause the market price of our Common Stock to decline and may result in dilution to our existing shareholders.

We filed a shelf registration statement on Form S-3 on October 19, 2020, and amendments thereto on December 10, 2020, February 8, 2021, and February 19, 2021, which the SEC declared effective on February 24, 2021 (the "February 2021 S-3"). The February 2021 S-3 allows us to issue up to $75 million in securities including Common Stock, preferred stock, debt securities, warrants and units, and is intended to provide us with increased financial flexibility and more efficient access to the capital markets. On August 25, 2021, we entered into an At-The-Market Equity Offering Sales Agreement with Stifel, Nicolaus & Company, Incorporated, as sales agent and/or principal ("Stifel"), pursuant to which we may offer and sell, from time to time through or to Stifel, up to 3,000,000 shares of our Common Stock under the February 2021 S-3. We have also issued shares of our Common Stock in private transactions. The 1,200,000 shares of Common Stock we issued in a private transaction on April 30, 2021, and the 2,349,207 shares of Common Stock we issued in a private transaction on September 24, 2021, as consideration for the acquisition of certain mineral and royalty assets, have been registered with the SEC through the filing of resale registration statements on Form S-3, which the SEC declared effective on June 11, 2021, and November 5, 2021, respectively.

We cannot predict the effect, if any, that market sales of these securities or the availability of the securities will have on the prevailing market price of our Common Stock from time to time. Substantial sales of shares of our Common Stock or other securities in the public market, or the perception that those sales could occur, may cause the market price of our Common Stock to decline. Such a decrease in our share price could in turn impair our ability to raise capital through the sale of additional equity securities. In addition, any such decline may make it more difficult for shareholders to sell shares of our Common Stock at prices they deem acceptable.

As of September 30, 2021, we were authorized to issue an aggregate of 36,000,500 shares of Common Stock. At our Special Meeting of Shareholders held on October 5, 2021, the shareholders approved an amendment to our Amended and Restated Certificate of Incorporation to increase the number of authorized shares of Common Stock to 54,000,500 shares of which 32,970,819 shares were issued and outstanding on December 3, 2021. Future issuances of our Common Stock, or other securities convertible into our Common Stock, may result in significant dilution to our existing shareholders. Significant dilution would reduce the proportionate ownership and voting power held by our existing shareholders.

We may reduce or suspend our dividend in the future.

We have paid a quarterly dividend for many years. Our most recent quarterly dividend was $0.01 per share, and we have paid a quarterly dividend of $0.01 per share or $0.04 per share for the past three years. In the future our Board may, without advance notice, determine to reduce or suspend our dividend in order to maintain our financial flexibility and best position us for long-term success. The declaration and amount of future dividends is at the discretion of our Board and will depend on our financial condition, results of operations, cash flows, prospects, industry conditions, capital requirements and other factors and restrictions our Board deems relevant. The likelihood that dividends will be reduced or suspended is increased during periods of prolonged market weakness. In addition, our ability to pay dividends may be limited by agreements governing our indebtedness now or in the future. Although we do not currently have plans to reduce or suspend our dividend, there can be no assurance that we will not reduce our dividend or that we will continue to pay a dividend in the future.

If we cannot meet the NYSE continued listing requirements, the NYSE may delist our Common Stock.

Our Common Stock is currently listed on the NYSE. In the future, if we are unable to meet the continued listing requirements of the NYSE, including, among other things, (i) the requirement of maintaining a minimum average closing price of $1.00 per share over a consecutive 30 trading-day period and (ii) the requirement of maintaining an average market capitalization of not less than $50 million over a 30 trading-day period with, at the same time, stockholders' equity not less than $50 million, we would fall below compliance standards and risk having our Common Stock delisted. In addition, in the event of an abnormally low share price of our Common Stock and/or we fail to maintain an average market capitalization of at least $15 million over a 30-trading day period, we would be subject to immediate delisting under the NYSE's rules without any opportunity to cure. A delisting of our Common Stock could negatively impact us by, among other things, the following:

- causing our shares to be transferred to a more limited market than the NYSE, which could affect the market price, trading volume, liquidity and resale price of such shares;
- reducing the number of investors, including institutional investors, willing to hold or acquire our Common Stock, which could negatively impact our ability to raise equity;
- decreasing the amount of news and analyst coverage relating to us;
- limiting our ability to issue additional securities, obtain additional financing or pursue strategic restructuring, refinancing or other transactions; and
- impacting our reputation and, as a consequence, our business.

ITEM 1B. Staff Comments

None

ITEM 2. Properties

General Background

We are focused on perpetual natural gas and oil mineral ownership in resource plays in the United States. As part of our evolution as a company, we also own interests in leasehold acreage and non-operated working interests in natural gas and oil properties.

At September 30, 2021, our principal properties consisted of (i) perpetual ownership of 251,600 net mineral acres, held principally in Oklahoma, Texas, Louisiana, North Dakota and Arkansas; (ii) leases on 18,298 net acres primarily in Oklahoma; and (iii) working interests, royalty interests or both in 6,457 producing natural gas and oil wells and 277 wells in the process of being drilled or completed.

Management's Business Strategy Related to Properties

During fiscal year 2019, we made the strategic decision to focus on perpetual natural gas and oil mineral ownership and growth through mineral acquisitions and the development of our significant mineral acreage inventory in our core areas of focus. In accordance with this strategy, we no longer participate in new development on our mineral or leasehold acreage with a cost-bearing working interest. We believe that our strategy to focus on mineral ownership is the best path to giving our shareholders the greatest risk-weighted returns on their investments.

Our goal is to increase shareholder value through the active management of our fee mineral and leasehold assets. We plan to grow our mineral fee holdings by acquiring mineral acreage, in the core areas of resource plays with substantial undeveloped opportunities, that meets or exceeds our corporate return threshold. We also plan to proactively lease our mineral holdings. We have an active program in place focused on leasing open acreage to generate additional lease bonus revenue and future royalty revenue.

Title to Properties

Consistent with industry practice, we do not have current abstracts or title opinions on all of our mineral acreage and, therefore, cannot be certain that we have unencumbered title to all of these properties. In recent years, a few insignificant challenges have been made against our fee title to our acreage.

Acreage

Mineral Interests Owned

The following table of mineral interests owned reflects, in each respective state, the number of (i) net and gross acres owned by the Company, (ii) net and gross producing acres owned by the Company, (iii) net and gross acres leased to others by the Company and (iv) net and gross acres open (unleased) as of September 30, 2021.

State	Net Acres	Gross Acres	Net Acres Producing (1)	Gross Acres Producing (1)	Net Acres Leased to Others (2)	Gross Acres Leased to Others (2)	Net Acres Open (3)	Gross Acres Open (3)
Oklahoma	110,967	931,688	46,857	373,510	5,652	37,291	58,458	520,887
Texas	40,336	337,670	5,690	55,795	5,960	44,637	28,686	237,238
Louisiana	560	26,728	560	26,728	-	-	-	-
North Dakota	14,302	78,096	2,772	14,483	-	-	11,530	63,613
Arkansas	11,934	51,253	7,183	27,145	-	-	4,751	24,108
Other	73,501	260,233	1,152	8,590	268	615	72,081	251,028
Total:	**251,600**	**1,685,668**	**64,214**	**506,251**	**11,880**	**82,543**	**175,506**	**1,096,874**

(1) "Producing" represents the mineral acres in which PHX owns a royalty or working interest in a producing well.
(2) "Leased" represents the mineral acres owned by PHX that are leased to third parties but not producing.

(3) "Open" represents mineral acres owned by PHX that are not leased or in production.

Leases

The following table reflects our net mineral acres leased from others, lease expiration dates, and net leased acres held by production as of September 30, 2021. Net acres increased in 2021 due to the purchase of overriding royalty interests.

		Net Acres Expiring					
State	Net Acres	2021	2022	2023	2024	2025	Net Acres Held by Production
Oklahoma	12,827	-	-	-	-	-	12,827
Texas	2,229	-	-	-	-	-	2,229
Arkansas	2,159	-	-	-	-	-	2,159
Other	1,083	-	-	-	-	-	1,083
TOTAL	18,298	-	-	-	-	-	18,298

Proved Reserves

Summary of Proved Reserves

The following table summarizes estimates of proved reserves of natural gas, oil and NGL held by the Company as of September 30, 2021, compared to the two preceding year ends, using prices and costs under existing economic conditions. Proved reserves are located onshore within the contiguous United States and are principally made up of small interests in 6,457 wells, which are predominately located in the Mid-Continent region. Other than this Annual Report, our reserve estimates are not filed with any federal agency.

Summary of Proved Natural Gas and Oil Reserves

	Natural Gas (Mcf)	Oil (Bbl)	NGL (Bbl)	Total Proved (Mcfe)
Net Proved Developed Reserves				
September 30, 2021	60,287,881	1,439,860	1,467,092	77,729,593
September 30, 2020	40,924,083	1,148,989	1,135,864	54,633,201
September 30, 2019	67,713,193	1,863,096	1,747,242	89,375,221
Net Proved Undeveloped Reserves				
September 30, 2021	4,664,787	64,980	34,761	5,263,233
September 30, 2020	1,448,690	184,668	83,993	3,060,656
September 30, 2019	12,560,713	516,994	226,038	17,018,905
Net Total Proved Reserves				
September 30, 2021	64,952,668	1,504,840	1,501,853	82,992,826
September 30, 2020	42,372,773	1,333,657	1,219,857	57,693,857
September 30, 2019	80,273,906	2,380,090	1,973,280	106,394,126

Exploration and development of our natural gas and oil properties is conducted by natural gas and oil exploration and production companies, primarily larger independent operating companies. We do not operate any of our natural gas and oil properties.

For the year ended September 30, 2021, our net total proved reserves increased by 25.3 Bcfe, as compared to September 30, 2020. The increase in total proved reserves from 2020 to 2021 is attributable to a combination of the following factors:

- Positive pricing revisions of 28.1 Bcfe comprised of (i) proved developed revisions of 28.7 Bcfe due to natural gas and oil wells extending their economic limits later than was projected in 2020 due to higher gas and oil prices and other reserve parameters, such as differentials and lease operating costs, partially offset by (ii) proved undeveloped negative revisions of 0.6 Bcfe resulting from permits that expired and were not renewed by the operator, as locations are only considered PUD if they are permitted, in progress, or drilled and uncompleted (DUC).

- The acquisition of 8.6 Bcfe, predominately in the active drilling programs of the Haynesville Shale play in east Texas and western Louisiana and the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma, of which 4.0 Bcfe were proved developed and 4.6 Bcfe were proved undeveloped.

- Reserve extensions, discoveries and other additions of 0.7 Bcfe (comprised of 0.4 Bcfe proved developed and 0.3 Bcfe proved undeveloped reserves) principally resulting from: (i) our royalty interest ownership in the ongoing development of unconventional natural gas, oil and NGL utilizing horizontal drilling in the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma; and (ii) our royalty interest ownership in the ongoing development of unconventional natural gas, oil and NGL utilizing horizontal drilling in the Anadarko Granite Wash play, which is part of the deep Anadarko Basin in Oklahoma and Texas.

- Production of 9.1 Bcfe from the Company’s natural gas and oil properties.

- Negative performance revisions of 2.1 Bcfe (comprised of all proved developed), principally due to lower performance of high-interest Mississippian and Woodford wells in the STACK play in Oklahoma that were brought online in 2021, and therefore converted from proved undeveloped to proved producing reserves year over year, and, to a lesser extent, lower performance in the Fayetteville Shale gas properties in Arkansas and Anadarko Basin Granite Wash gas properties in Western Oklahoma.

- The sale of 0.9 Bcfe proved developed, consisting of predominately working interest in low rate, legacy vertical wells in Oklahoma.

Proved Undeveloped Reserves

The following details the changes in proved undeveloped reserves for fiscal year 2021 (Mcfe):

Beginning proved undeveloped reserves	3,060,656
Proved undeveloped reserves transferred to proved developed	(2,060,368)
Revisions	(629,317)
Extensions and discoveries	246,993
Sales	-
Purchases	4,645,269
Ending proved undeveloped reserves	5,263,233

During fiscal year 2021, total net PUD reserves increased by 2.2 Bcfe. In fiscal year 2021, a total of 2.1 Bcfe (67% of the beginning balance) was transferred to proved developed. The remaining balance of approximately 4.3 Bcfe (140% of the beginning balance) of positive revisions to PUD reserves consist of acquisitions of 4.6 Bcfe in the Haynesville Shale in Texas and Louisiana and Meramec and Woodford SCOOP play in Oklahoma, and additions and extensions of 0.2 Bcfe within the active drilling program areas of (i) STACK Meramec and Woodford in western Oklahoma, (ii) the SCOOP Woodford Shale in western Oklahoma and (iii) Bakken in North Dakota. These were slightly offset by negative pricing revisions of 0.6 Bcfe resulting from permits that expired and were not renewed by the operator, as locations are only considered PUD if they are permitted, in progress, or drilled and uncompleted (DUC).

We anticipate that all our current PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves, which are no longer projected to be drilled within five years from the date they were added to PUD reserves, will be removed as revisions at the time that determination is made. In the event that there are undrilled PUD locations at the end of the five-year period, it is our intent to remove the reserves associated with those locations from our proved reserves as revisions.

Estimated Future Net Cash Flows

Set forth below are estimated future net cash flows with respect to our net proved reserves (based on the estimated units set forth above in Proved Reserves) for each of the years indicated, and the present value of such estimated future net cash flows, computed by applying a 10% discount factor as required by SEC rules and regulations. We follow the SEC rule, *Modernization of Oil* *and Gas Reporting Requirements*. In accordance with the SEC rule, the estimated future net cash flows were computed using the 12-month average price calculated as the unweighted arithmetic average of the first-day-of-the-month individual product prices for each month within the 12-month period prior to September 30 held flat over the life of the properties and applied to future production of proved reserves less estimated future development and production expenditures for these reserves. The amounts presented are net of operating costs and production taxes levied by the respective states. Prices used for determining future cash flows from natural gas, oil and NGL as of September 30, 2021, 2020 and 2019, were as follows: in fiscal year 2021, $2.79/Mcf for natural gas, $56.51/Bbl for oil and $20.58/Bbl for NGL; in fiscal year 2020, $1.62/Mcf for natural gas, $40.18/Bbl for oil and $9.95/Bbl for NGL; and in fiscal year 2019, $2.48/Mcf for natural gas, $54.40/Bbl for oil and $19.30/Bbl for NGL. These future net cash flows based on SEC pricing rules should not be construed as the fair market value of our reserves. A market value determination would need to include many additional factors, including anticipated natural gas, oil and NGL price and production cost increases or decreases, which could affect the economic life of the properties.

Estimated Future Net Cash Flows

	9/30/2021	9/30/2020	9/30/2019
Proved Developed	$ 163,339,707	$ 57,306,480	$ 161,943,514
Proved Undeveloped	16,244,436	8,779,289	48,900,497
Income Tax Expense	(40,697,140)	(13,224,535)	(47,788,416)
Total Proved	$ 138,887,003	$ 52,861,234	$ 163,055,595

10% Discounted Present Value of Estimated Future Net Cash Flows

	9/30/2021	9/30/2020	9/30/2019
Proved Developed	$ 86,793,303	$ 33,270,804	$ 86,814,212
Proved Undeveloped	9,731,036	5,659,479	23,581,427
Income Tax Expense	(21,733,997)	(7,796,130)	(24,834,110)
Total Proved	$ 74,790,342	$ 31,134,153	$ 85,561,529

Evaluation and Review of Reserves

The determination of reserve estimates is a function of testing and evaluating the production and development of natural gas and oil reservoirs in order to establish a production decline curve. The established production decline curves, in conjunction with natural gas and oil prices, development costs, production taxes and operating expenses, are used to estimate natural gas and oil reserve quantities and associated future net cash flows. As information is processed regarding the development of individual reservoirs, and as market conditions change, estimated reserve quantities and future net cash flows will change over time as well. Estimated reserve quantities and future net cash flows are affected by changes in product prices. These prices have varied substantially in recent years and are expected to vary substantially from current pricing in the future.

We follow the SEC's modernized oil and natural gas reporting rules, which were effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. See Note 16 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" for disclosures regarding our natural gas and oil reserves.

Under the SEC rules, oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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 natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural 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. 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: (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. 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.

Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor, compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserve estimate, if the extraction is by means not involving a well.

Undeveloped oil and natural 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. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, prepared our natural gas, oil and NGL reserves estimates as of September 30, 2021, 2020 and 2019 (see Exhibits 23.2 and 99). Within DeGolyer and MacNaughton, the technical person primarily responsible for preparing the estimates set forth in the Report of DeGolyer and MacNaughton dated October 1, 2021, filed as Exhibit 99 to this Annual Report on Form 10-K, was Dr. Dilhan Ilk. Dr. Ilk is a Senior Vice President with DeGolyer and MacNaughton, Division Manager of the firm's North America Division, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers. Dr. Ilk has a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010. He has over 10 years of experience in oil and gas reservoir studies and reserves evaluations. Dr. Ilk 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 and 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.

All of the reserve estimates are reviewed and approved by our Director of Engineering, Danielle Mezo. Ms. Mezo holds a Bachelor of Science degree in Petroleum Engineering from the University of Oklahoma and a Professional Engineering License in Petroleum Engineering in the State of Oklahoma. Ms. Mezo has more than 10 years of experience in the oil and gas industry.

Our Director of Engineering and internal staff work closely with our Independent Consulting Petroleum Engineers to ensure the integrity, accuracy and timeliness of data furnished to them for their reserves estimation process. We provide historical information (such as ownership interest, gas and oil production, well test data, commodity prices, operating costs, handling fees, and development costs) for all properties to our Independent Consulting Petroleum Engineers. Throughout the year, our team meets regularly with representatives of our Independent Consulting Petroleum Engineers to review properties and discuss methods and assumptions. Our net proved natural gas, oil and NGL reserves (including certain undeveloped reserves described above) are located onshore in the contiguous United States. All studies have been prepared in accordance with regulations prescribed by the SEC. The reserve estimates were based on economic and operating conditions existing at September 30, 2021, 2020 and 2019. Since the determination and valuation of proved reserves is a function of testing and estimation, the reserves presented are expected to change as future information becomes available.

Natural Gas, Oil and NGL Production

The following table sets forth our net production of natural gas, oil and NGL for the fiscal periods indicated.

	Year Ended 9/30/2021	Year Ended 9/30/2020	Year Ended 9/30/2019
Mcf - Natural Gas	6,699,720	5,962,705	7,086,761
Bbls - Oil	224,479	269,785	329,199
Bbls - NGL	171,488	168,623	216,259
Mcfe	9,075,519	8,593,153	10,359,509

Average Sales Prices and Production Costs

The following tables set forth unit price and cost data for the fiscal periods indicated.

Average Sales Price	Year Ended 9/30/2021	Year Ended 9/30/2020	Year Ended 9/30/2019
Per Mcf, Natural Gas	$ 3.13	$ 1.72	$ 2.48
Per Bbl, Oil	$ 56.58	$ 41.47	$ 55.07
Per Bbl, NGL	$ 23.80	$ 11.42	$ 17.10
Per Mcfe	$ 4.16	$ 2.72	$ 3.80

Average Production (lifting) Costs	Year Ended 9/30/2021	Year Ended 9/30/2020	Year Ended 9/30/2019
(Per Mcfe)			
Well Operating Costs (1)	$ 1.11	$ 1.12	$ 1.21
Production Taxes (2)	0.21	0.12	0.18
	$ 1.32	$ 1.24	$ 1.39

(1) Includes actual well operating costs, compression, handling and marketing fees paid on natural gas sales and other minor expenses associated with well operations.
(2) Includes production taxes only.

In fiscal year 2021, approximately 49% of our natural gas, oil and NGL revenue was generated from royalty payments received on our mineral acreage. Royalty interests bear no share of the field operating costs on those producing wells, but they do bear a share of the handling fees (primarily gathering and transportation).

Gross and Net Productive Wells and Developed Acres

The following table sets forth our gross and net productive natural gas and oil wells as of September 30, 2021. We own either working interests, royalty interests or both in these wells. We do not operate any wells.

	Gross Working Interest Only Wells	Net Working Interest Only Wells	Gross Working Interest and Royalty Interest Wells	Net Working Interest and Royalty Interest Wells	Gross Royalty Only Wells	Net Royalty Only Wells	Total Gross Wells
Natural Gas	396	10.07	982	41.39	3,072	19.87	4,450
Oil	115	13.97	103	3.65	1,789	11.86	2,007
Total	511	24.04	1,085	45.04	4,861	31.73	6,457

Our average interest in royalty interest only wells is 0.65%. Our average interest in working interest wells is 4.33% working interest and 4.19% net revenue interest.

Information on multiple completions is not available from our records, but the number is not believed to be significant. With regard to Gross Royalty Only Wells, some of these wells are in multi-well unitized fields. In such cases, our ownership in each unitized field is counted as one gross well, as we do not have access to the actual well count in all of these unitized fields.

As of September 30, 2021, we owned 506,251 gross (64,214 net) developed mineral acres. We had also leased from others 191,793 gross (18,298 net) developed acres.

Undeveloped Acreage

As of September 30, 2021, we owned 1,179,417 gross and 187,386 net undeveloped mineral acres. All of our leases are held by production ("HBP"), and we do not have any leases on undeveloped acres.

Drilling Activity

The following table sets forth our net productive development, exploratory and purchased wells and net dry development, exploratory and purchased wells in which we had either a working interest, a royalty interest or both were drilled and completed during the fiscal years indicated.

	Net Productive Working Interest Wells	Net Productive Royalty Interest Wells	Net Dry Working Interest Wells
Development Wells			
Fiscal years ended:			
September 30, 2021	-	0.556684	-
September 30, 2020	-	0.597278	-
September 30, 2019	0.939636	0.395755	-
Exploratory Wells			
Fiscal years ended:			
September 30, 2021	-	-	-
September 30, 2020	-	-	-
September 30, 2019	-	-	-
Purchased Wells			
Fiscal years ended:			
September 30, 2021	-	1.216467	-
September 30, 2020	-	0.364206	-
September 30, 2019	-	0.516293	-

Present Activities

The following table sets forth our gross and net natural gas and oil wells being drilled or waiting on completion as of September 30, 2021, in which we own either a working interest, a royalty interest or both. These wells were not producing at September 30, 2021.

	Gross Working Interest Wells	Net Working Interest Wells	Gross Royalty Only Wells	Total Net Royalty Interest Wells
Natural Gas	-	-	131	0.63
Oil	-	-	146	0.73
Total	-	-	277	1.36

Other Facilities

We have an office lease on 8,776 square feet of office space in Oklahoma City, Oklahoma, which is scheduled to expire on August 31, 2027.

ITEM 3. Legal Proceedings

In the ordinary course of business, we may be, from time to time, a claimant or a defendant in various legal proceedings. There were no material pending legal proceedings involving the Company on September 30, 2021, or at the date of this Annual Report.

ITEM 4. Mine Safety Disclosures

Not applicable.

PART II

ITEM 5. Market for Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Market for our Common Stock

Our Common Stock is listed on the New York Stock Exchange (NYSE) under the trading symbol "PHX."

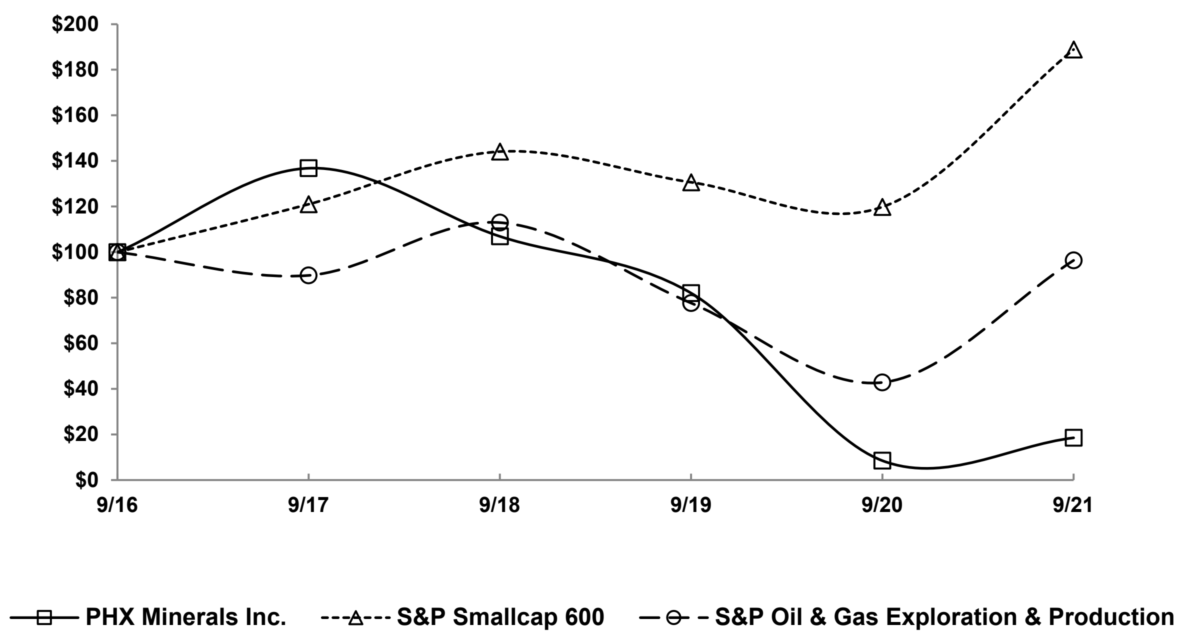
As of September 30, 2021, we were authorized to issue an aggregate of 36,000,500 shares of Common Stock. At our Special Meeting of Shareholders held on October 5, 2021, our shareholders approved an amendment to our Amended and Restated Certificate of Incorporation to increase our authorized shares to 54,000,500 shares of Common Stock.

Performance Graph

The following graph compares the 5-year cumulative total return provided shareholders on our Common Stock relative to the cumulative total returns of the S&P Smallcap 600 Index and the S&P Oil & Gas Exploration & Production Index. An investment of $100 (with reinvestment of all dividends) is assumed to have been made in our Common Stock and in each of the indexes on September 30, 2016, and the relative performance of such investment is tracked through and including September 30, 2021. This table is not intended to forecast future performance of our Common Stock.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among PHX Minerals Inc., the S&P Smallcap 600 Index
and the S&P Oil & Gas Exploration & Production Index



*$100 invested on 9/30/16 in stock or index, including reinvestment of dividends.
Fiscal year ending September 30.

Record Holders

At December 3, 2021, there were 1,273 holders of record of our Common Stock and approximately 5,000 beneficial owners.

Dividends

During the past three years, we have paid quarterly dividends of either $0.04 per share or $0.01 per share on our Common Stock. Approval by our Board is required before the declaration and payment of any dividends.

Historically, we have paid dividends to our shareholders on a quarterly basis. While we anticipate we will continue to pay dividends on our Common Stock, the payment and amount of future cash dividends will depend upon, among other things, financial condition, funds from operations, the level of capital and development expenditures, future business prospects, contractual restrictions and any other factors considered relevant by the Board. Our Credit Agreement sets limits on dividend payments and stock repurchases if those payments would cause the Leverage Ratio (as defined in the Credit Agreement) to go above 2.50 to 1.0 or the Available Commitment (as defined in the Credit Agreement) to go below ten percent of the Borrowing Base (as defined in the Credit Agreement).

Purchases of Equity Securities by the Company

During the quarter ended September 30, 2021, we did not repurchase any shares of our Common Stock.

Following approval by our shareholders of our 2010 Restricted Stock Plan ("2010 Stock Plan") in March 2010, as amended in May 2018, our Board approved our repurchase program which, as amended, authorizes management to repurchase up to $1.5 million of our Common Stock at our discretion. The repurchase program has an evergreen provision which authorizes the repurchase of an additional $1.5 million of our Common Stock when the previous amount is utilized. As part of the amendment, the number of shares allowed to be purchased by us under the repurchase program is no longer capped at an amount equal to the aggregate number of shares of Common Stock (i) awarded pursuant to our 2010 Stock Plan, as amended, (ii) contributed by us to the PHX Minerals Inc. Employee Stock Ownership and 401(k) Plan, a tax qualified, defined contribution plan (the "ESOP") and (iii) credited to the accounts of directors pursuant to our Deferred Compensation Plan for Non-Employee Directors.

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. Our actual results could differ materially from those discussed in these forward-looking statements as a result of many factors, including those discussed under "Risk Factors" and elsewhere in this Annual Report. The following discussion and analysis generally discuss fiscal year 2021 and 2020 items and fiscal year-to-year comparisons between 2021 and 2020. Discussions of 2019 items and year-to-year comparisons between 2020 and 2019 that are not included in this Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended September 30, 2020.

Business Overview

We are focused on perpetual natural gas and oil mineral ownership in resource plays in the United States. Prior to a strategy change in 2019, we participated with a working interest on some of our mineral and leasehold acreage and as a result, we still have legacy interests in leasehold acreage and non-operated interests in natural gas and oil properties. Effective October 8, 2020, our corporate name was changed to PHX Minerals Inc. to more accurately reflect our business strategy.

Our results of operations are dependent primarily upon the Company's: existing reserve quantities; costs associated with acquiring, exploring for and developing new reserves; production quantities and related production costs; and natural gas, oil and NGL sales prices. Although a significant amount of our revenues is currently derived from the production and sale of natural gas, oil and NGL on our working interests, a growing portion of our revenues is derived from royalties granted from the production and sale of natural gas, oil and NGL.

Strategic Focus on Mineral Ownership

During fiscal year 2019, we made the strategic decision to focus on perpetual natural gas and oil mineral ownership and growth through mineral acquisitions and the development of our significant mineral acreage inventory in our core areas of focus. In accordance with this decision, we ceased taking working interest positions on our mineral and leasehold acreage going forward. In fiscal years 2020 and 2021, we did not participate with a working interest in the drilling of any new wells. We believe that our strategy to focus on mineral ownership is the best path to giving our shareholders the greatest risk-weighted returns on their investments.

Market Conditions and Commodity Prices

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 production volumes or revenues.

Our working interest and royalty revenues may vary significantly from period to period as a result of changes in commodity prices, production mix and volumes of production sold by our operators.

Production and Operational Update

Our natural gas and NGL production for the fiscal year 2021 increased 12% and 2%, respectively, while oil production decreased 17% from that of 2020. The 2021 fiscal year's higher natural gas, oil and NGL prices (as discussed below) and the overall production changes noted above resulted in a 62% increase in revenues from the sale of natural gas, oil and NGL in 2021.

Our proved natural gas, oil and NGL reserves increased to 83.0 Bcfe in 2021, compared to 57.7 Bcfe in 2020, an increase of approximately 25.3 Bcfe, or 44%. The increase was primarily due to improved gas and oil prices and acquisitions, slightly offset by production and performance revisions. The revisions were primarily related to natural gas and oil wells extending their economic limits later than was projected in 2020 due to higher gas and oil prices and other reserve parameters, such as differentials and lease operating costs. This was coupled with acquisitions predominately located in the active drilling programs of the Haynesville Shale play in east Texas and western Louisiana and the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma.

As of September 30, 2021, we owned an average 0.5% net revenue interest, consisting of all royalty interest, in 277 wells that were being drilled or awaiting completion.

Results of Operations

The following table reflects certain operating data for the periods presented:

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Production:			
Natural Gas (Mcf)	6,699,720	5,962,705	12%
Oil (Bbls)	224,479	269,785	(17%)
NGL (Bbls)	171,488	168,623	2%
Mcfe	9,075,519	8,593,153	6%
Average Sales Price:			
Natural Gas (per Mcf)	$3.13	$1.72	82%
Oil (per Bbl)	$56.58	$41.47	36%
NGL (per Bbl)	$23.80	$11.42	108%
Mcfe	$4.16	$2.72	53%

Production by quarter for 2021 and 2020 was as follows (Mcfe):

	For the Year Ended September 30, 2021		
	Royalty Interest	Working Interest	Total
First quarter	744,653	1,329,681	2,074,334
Second quarter	1,230,105	1,066,697	2,296,802
Third quarter	1,204,571	1,288,242	2,492,813
Fourth quarter	998,230	1,213,340	2,211,570
Total	4,177,559	4,897,960	9,075,519

	For the Year Ended September 30, 2020		
	Royalty Interest	Working Interest	Total
First quarter	785,431	1,493,056	2,278,487
Second quarter	971,589	1,401,546	2,373,135
Third quarter	814,501	1,089,251	1,903,752
Fourth quarter	776,276	1,261,503	2,037,779
Total	3,347,797	5,245,356	8,593,153

Fiscal Year 2021 Compared to Fiscal Year 2020

Overview

Revenues decreased in 2021 primarily due to an increase in losses on derivative contracts, partially offset by higher natural gas, oil and NGL sales. We recorded a net loss of $6,217,237, or $0.24 per share, in 2021, compared to net loss of $23,952,037, or $1.41 per share, in 2020. Expenses decreased in 2021, primarily the result of decreases in provision for impairment (non-cash), DD&A, LOE and interest expense, partially offset by an increase in transportation, gathering and marketing expenses, production taxes and loss on debt extinguishment.

Natural Gas, Oil and NGL Sales

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Natural gas, oil and NGL sales	$ 37,749,044	$ 23,370,003	62%

The increase was due to increased natural gas, oil and NGL prices of 82%, 36% and 108%, respectively, combined with higher natural gas and NGL volumes of 12% and 2%, respectively, partially offset by lower oil volumes of 17%.

The increase in natural gas production was primarily due to acquisitions in the Haynesville Shale play of Texas and Louisiana, and slightly offset by naturally declining production in the SCOOP and Arkoma STACK. The decrease in oil production was a result of naturally declining production in high interest wells in the Eagle Ford and Bakken plays, our strategy of no longer participating with working interest in new drilling in the Eagle Ford, and reduced drilling activity in the Bakken. These decreases were slightly offset by acquisitions and new drilling in the STACK. The increase in NGL production is primarily attributable to high interest wells coming back online after being shut-in for part of fiscal year 2020, as well as new wells being brought online in the STACK. This was slightly offset by naturally declining production in the SCOOP.

Given our strategic decision to cease participating with working interests, we plan to offset the natural decline of our existing production base by the development of our current inventory of mineral acreage and through acquisitions of additional mineral interests going forward.

Gains (Losses) on Derivative Contracts

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Cash received (paid) on settled derivative contracts:			
Cash received (paid) on settled derivative contracts, net	$ (11,925,669)	$ 4,109,210	(390%)
Non-cash gain (loss) on derivative contracts:			
Non-cash gain (loss) on derivative contracts, net	$ (4,276,820)	$ (3,201,791)	(34%)
Gains (losses) on derivative contracts, net	$ (16,202,489)	$ 907,419	(1,886%)

	As of September 30,		
	2021	2020	
Fair value of derivative contracts			
Net asset (net liability)	$ (13,784,467)	$ (707,647)	(1,848%)

The change in net loss on derivative contracts was due to the natural gas and oil collars and fixed price swaps being less beneficial in 2021 in relation to their respective contracted volumes and prices. The change from a net liability position of $707,647 at September 30, 2020, to a net liability position of $13,784,467 at September 30, 2021, resulted from non-cash loss on derivative contracts in the 2021 period of $4,276,820 and entry into off-market hedges with BP Energy Company ("BP") for $8.8 million in cash. See Note 12 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" for further explanation.

Our natural gas and oil fixed price swaps in place at September 30, 2021, had expiration dates of through March 2023. We utilize derivative contracts for the purpose of protecting our cash flow and return on investments.

Lease Operating Expenses (LOE)

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Lease operating expenses	$ 4,230,968	$ 4,841,541	(13%)
Lease operating expenses per MCFE	$ 0.47	$ 0.56	(16%)

We are responsible for a portion of LOE relating to a well as a working interest owner. LOE includes normal recurring and nonrecurring expenses associated with our working interests necessary to produce hydrocarbons from our natural gas and oil wells, including maintenance, repairs, salt water disposal, insurance and workover expenses. Total LOE related to field operating costs decreased $610,573 or 13% in 2021, compared to 2020. The decrease in LOE rate was principally the result of our strategic decision to cease participating with a working interest in new wells and the increase in royalty interest production as a percentage of total production.

Transportation, Gathering and Marketing

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Transportation, gathering and marketing	$ 5,767,287	$ 4,812,869	20%
Transportation, gathering and marketing per MCFE	$ 0.64	$ 0.56	14%

Transportation, gathering and marketing increased $954,418, or 20%, in 2021, compared to 2020. This increase in costs was primarily due to increased production in 2021. The increase in rate per Mcfe was primarily due to the increase in natural gas sales in relation to other products. Natural gas sales bear the large majority of our transportation, gathering and marketing fees.

Production Taxes

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Production taxes	$ 1,938,304	$ 1,022,912	89%
Production taxes as % of sales	5.1%	4.4%	16%

Production taxes are paid on produced natural gas and oil based on a percentage of revenues from products sold at both fixed and variable rates established by federal, state or local taxing authorities. Production taxes increased $915,392, or 89%, in 2021, compared to 2020. The increase in amount was primarily the result of increased natural gas, oil and NGL sales of $14,379,041 during 2021.

Depreciation, Depletion and Amortization (DD&A)

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Depreciation, depletion and amortization	$ 7,745,804	$ 11,313,783	(32%)
Depreciation, depletion and amortization per MCFE	$ 0.85	$ 1.32	(36%)

DD&A is the amount of cost basis of natural gas and oil properties attributable to the volume of hydrocarbons extracted during such period, calculated on a units-of-production basis for working interest, and on a straight-line basis for producing and non-producing minerals. Estimates of proved developed producing reserves are a major component of the calculation of depletion. DD&A decreased $3,567,979, or 32%, in 2021 compared to 2020, of which $4,204,702 of the decrease resulted from a $0.47 decrease in the DD&A rate per Mcfe, partially offset by an increase of $636,723 resulting from production increasing 6% in 2021. The rate decrease was partially due to higher natural gas, oil and NGL prices utilized in the reserve calculations during the 2021 period, as compared to 2020 period, lengthening the economic life of wells. This resulted in higher projected remaining reserves on a significant number of wells causing decreased units of production DD&A, despite the increase in projection.

Provision for Impairment

Provision for impairment was $50,475 in 2021, as compared to $29,904,528 provision for impairment in 2020. During 2021, impairment of $37,879 was related to one field. These assets were written down to their fair market value as required by GAAP. During 2020, impairment of $29,315,806 was recorded on seven different fields including the Fayetteville and Eagle Ford shales, which represented 89% of our total impairment. The impairment in these seven fields was caused by lower future prices reducing future net cash flows associated with these fields, which caused these assets to fail the step one test for impairment as their undiscounted cash flows were not high enough to cover the book basis of the assets. These assets were written down to their fair market value as required by GAAP. The remaining $12,596 and $588,721 of impairment in the 2021 and 2020 periods, respectively, were recorded on other assets.

Interest Expense

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Interest Expense	$ 995,127	$ 1,286,788	(23%)
Weighted average debt outstanding	$ 23,725,079	$ 32,290,257	(27%)

The decrease was due to a lower outstanding debt balance in 2021 compared to 2020.

General and Administrative Costs (G&A)

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
General and administrative	$ 8,207,882	$ 8,024,901	2%

G&A are costs not directly associated with the production of natural gas and oil and include the cost of employee salaries and related benefits, office expenses and fees for professional services. G&A for 2021 increased $182,981 as compared to 2020. The slight increase was primarily due to increased activity during the year, partially offset by our cost reduction efforts.

Loss on Debt Extinguishment

When we terminated our credit facility led by Bank of Oklahoma, we wrote-off all associated costs that had been previously capitalized.

Loss (Gain) on Asset Sales and Other

In 2021, we recorded a net gain on asset sales of $312,838 as compared to a net gain of $3,973,256 in 2020. During 2021, we sold 2,857 net mineral acres in Central Basin Platform in Texas for $285,714, resulting in a gain of $236,907. The remaining gain on asset sales in 2021 was due to various immaterial asset sales less adjustments.

During the first quarter of 2020, we sold producing mineral acreage in Eddy County, New Mexico, for a gain of $3,272,499. We utilized a like-kind exchange under Internal Revenue Code Section 1031 to defer income tax on all of the gain by offsetting it with the STACK/SCOOP mineral acreage acquisition that was purchased during the quarter using qualified exchange accommodation agreements. During the fourth quarter of 2020, we sold 5,925 non-producing mineral acres in northwestern Oklahoma for a gain of $717,640. The remaining gain on asset sales in 2020 was due to various asset sales less adjustments.

Provision (Benefit) for Income Taxes

	For the Year Ended September 30,		
	2021	2020	Percent Incr. or (Decr.)
Provision (benefit) for income taxes	$ (651,051)	$ (8,289,000)	(92%)
Effective tax rate	9%	26%	(65%)

Income taxes changed $7,637,949, from a $8,289,000 benefit in 2020 to a $651,051 benefit in 2021. The income tax benefit change resulted primarily from the reduction in net loss.

When a provision for income taxes is expected for the year, federal and Oklahoma excess percentage depletion decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is recorded.

Fiscal Year 2020 Compared to Fiscal Year 2019

Overview

Revenues decreased in 2020 primarily due to lower natural gas, oil and NGL sales, lower gains on asset sales and lower gains on derivative contracts. The Company recorded a net loss of $23,952,037, or $1.41 per share, in 2020, compared to net loss of

$40,744,938, or $2.43 per share, in 2019. Expenses decreased in 2020, primarily the result of decreases in provision for impairment (non-cash), DD&A, LOE and transportation, gathering and marketing expenses.

Natural Gas, Oil and NGL Sales

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Natural gas, oil and NGL sales	$ 23,370,003	$ 39,410,036	(41%)

The decrease was due to decreased natural gas, oil and NGL prices of 31%, 25% and 33%, respectively, combined with lower natural gas, oil and NGL volumes of 16%, 18% and 22%, respectively.

The decrease in oil production was a result of postponement of workovers due to prevailing economic conditions as well as naturally declining production in high interest wells in the Eagle Ford, and asset sales in 2019 and 2020 in the Permian Basin in Texas and New Mexico. These decreases were slightly offset by a ten-well drilling program in the Bakken that came online in November 2019 and mineral acquisitions of Bakken and STACK producing properties in late 2019. Decreased natural gas and NGL production was primarily due to naturally declining production in the Arkoma Stack and STACK and, to a lesser extent, the Fayetteville, as well as production downtime in high-interest wells in the Arkoma Stack.

Gains (Losses) on Derivative Contracts

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Cash received (paid) on derivative contracts:			
Cash received (paid) on derivative contracts, net	$ 4,109,210	$ 196,985	1,986%
Non-cash gain (loss) on derivative contracts:			
Non-cash gain (loss) on derivative contracts, net	$ (3,201,791)	$ 5,908,160	(154%)
Gains (losses) on derivative contracts, net	$ 907,419	$ 6,105,145	(85%)

	As of September 30,		
	2020	2019	
Fair value of derivative contracts			
Net asset (net liability)	$ (707,647)	$ 2,494,144	(128%)

The change in net gain on derivative contracts was principally due to natural gas and oil collars and fixed price swaps being more beneficial in 2019 in relation to their respective contracted volumes and prices. During fiscal year 2020, we received $4,109,210 on settled derivative contracts as compared to $196,985 received in fiscal year 2019. The change from a net asset position at September 30, 2019, to a net liability position at September 30, 2020 resulted in an unrealized loss on derivative contracts in fiscal year 2020 of $3,201,791.

The Company's natural gas and oil costless collar contracts and fixed price swaps in place at September 30, 2020, had expiration dates of October 2020 through February 2022. The Company utilizes derivative contracts for the purpose of protecting its cash flow and return on investments.

Gains on Asset Sales

In 2020, the Company recorded gain on asset sales of $3,997,436, as compared to $18,973,426 in 2019. During the first quarter of 2020, the Company sold producing mineral acreage in Eddy County, New Mexico, for a gain of $3,272,499. The Company utilized a like-kind exchange under Internal Revenue Code Section 1031 to defer income tax on all of the gain by offsetting it with the STACK/SCOOP mineral acreage acquisition that was purchased during the quarter using qualified exchange accommodation agreements. During the fourth quarter of 2020, the Company sold 5,925 non-producing mineral acres in northwestern Oklahoma for a gain of $717,640. The remaining gain on asset sales in 2020 was due to various asset sales less adjustments.

In 2019, the Company sold mineral acreage in Lea and Eddy Counties, New Mexico, for a gain of $9,096,938; Martin County, Texas, (mineral and leasehold) for a gain of $4,921,656; Loving, Reeves and Ward Counties, Texas, for a gain of $2,704,323; and Reagan and Upton Counties, Texas, for a gain of $2,250,509.

Lease Operating Expenses (LOE)

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Lease operating expenses	$ 4,841,541	$ 6,398,522	(24%)
Lease operating expenses per MCFE	$ 0.56	$ 0.62	(10%)

LOE related to field operating costs decreased $1,556,981 or 24% in 2020, compared to 2019. The decrease in LOE rate was principally the result of the Company's strategic decision to not participate with a working interest in new wells, selling some non-core marginal properties, which had higher operating costs and operators negotiating lower well service pricing resulting in lower LOE charges.

Transportation, Gathering and Marketing

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Transportation, gathering and marketing	$ 4,812,869	$ 6,089,903	(21%)
Transportation, gathering and marketing per MCFE	$ 0.56	$ 0.59	(5%)

Transportation, gathering and marketing decreased $1,277,034 or 21% in 2020, compared to 2019, primarily due to decreased production in 2020. The decrease in transportation, gathering and marketing rate was primarily due to decreased natural gas production coupled with decreased natural gas prices. Natural gas sales cause the majority of the handling. Handling fees are charged either as a percent of sales or based on production volumes.

Production Taxes

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Production taxes	$ 1,022,912	$ 1,902,636	(46%)
Production taxes as % of sales	4.4%	4.8%	(8%)

The decrease in amount was primarily the result of decreased natural gas, oil and NGL sales of $16,040,033 during 2020.

Depreciation, Depletion and Amortization (DD&A)

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Depreciation, depletion and amortization	$ 11,313,783	$ 18,196,583	(38%)
Depreciation, depletion and amortization per MCFE	$ 1.32	$ 1.76	(25%)

DD&A decreased $3,108,787 due to natural gas, oil and NGL production volumes decreasing 17% collectively in 2020, compared to 2019. An additional decrease of $3,774,013 was the result of a $0.44 decrease in the DD&A rate per Mcfe. The rate decrease was principally due to large impairments taken during the fourth quarter of fiscal year 2019 and the second quarter of fiscal year 2020, which lowered the basis of the assets. The rate decrease was partially offset by lower natural gas, oil and NGL prices utilized in the reserve calculations during fiscal year 2020, as compared to fiscal year 2019, shortening the economic life of wells. This resulted in lower projected remaining reserves on a significant number of wells causing increased units of production DD&A.

Provision for Impairment

Provision for impairment was $29,904,528 in 2020, as compared to $76,824,337 provision for impairment in 2019. During fiscal year 2020, impairment of $29,315,806 was recorded on seven different fields including the Fayetteville and Eagle Ford shales, which represent 89% of our total impairment. The impairment on assets in these seven fields was caused by lower futures prices associated with our products. Futures prices experienced downward pressure resulting in low pricing as of the end of the fiscal year 2020 second quarter. The reduced future net value associated with these fields caused the assets to fail the step one test for impairment as their undiscounted cash flows were not high enough to cover the book basis of the assets. These assets were written down to their fair market value as required by GAAP. The Fayetteville assets are dry-gas assets, of which the Company acquired a portion in 2011. Low natural gas prices at March 31, 2020, were the primary reason for impairment in this field. The Company recognized an impairment related to the Eagle Ford at September 30, 2019, of $76,560,376, primarily due to the removal of working interest PUDs from the Company's reserve report. The further impairment of the Eagle Ford assets at March 31, 2020, was due to the decline in commodity prices over fiscal year 2020 at that time. The remaining $588,721 and $263,961 of impairment was recorded on other assets in 2020 and 2019, respectively.

Interest Expense

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Interest Expense	$ 1,286,788	$ 1,995,789	(36%)
Weighted average debt outstanding	$ 32,290,257	$ 43,092,804	(25%)

The decrease was due to lower interest rates, on average, and a lower outstanding debt balance during 2020.

General and Administrative Costs (G&A)

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
General and administrative	$ 8,024,901	$ 8,565,243	(6%)

The decrease was primarily the result of lower personnel expenses and lower Board expenses. The decrease in personnel expenses was primarily due to the severance of approximately $670,000 upon the resignation of our former CEO toward the end of fiscal year 2019, reductions in work force and lower performance-related compensation. Lower Board expenses are due to fewer Board members in 2020, as compared to 2019. Personnel and Board expenses were partially offset by increased technical consulting and legal expenses. The increase in technical consulting was due to increased cost for our then interim (now current) CEO, geologic and engineering fees. The increase in legal expenses was primarily due to additional work provided pertaining to the Company's proxy statement, equity offering and general business advisement.

Provision (Benefit) for Income Taxes

	For the Year Ended September 30,		
	2020	2019	Percent Incr. or (Decr.)
Provision (benefit) for income taxes	$ (8,289,000)	$ (13,481,000)	(39%)
Effective tax rate	26%	25%	3%

In both 2020 and 2019, the tax benefits were the result of a large pretax loss from the impairments in the second quarter of 2020 and the fourth quarter of 2019.

When a provision for income taxes is expected for the year, federal and Oklahoma excess percentage depletion decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is recorded.

Liquidity and Capital Resources

At September 30, 2021, we had negative working capital of $2,912,862 which is inclusive of $12,087,988 of current derivative contract liabilities, as compared to positive working capital of $13,335,880 at September 30, 2020, which included $7.3 million of cash used for fiscal year 2021 first quarter acquisitions.

Liquidity

Cash and cash equivalents were $2,438,511 as of September 30, 2021, compared to $10,690,395 at September 30, 2020, a decrease of $8,251,884. Cash flows for the year ended September 30, 2021 and 2020, are summarized as follows:

	For the Year Ended September 30,		
Net cash provided (used) by:	2021	2020	Change
Operating activities	$ 3,942,087	$ 11,106,295	$ (7,164,208)
Investing activities	(20,368,919)	(6,462,518)	(13,906,401)
Financing activities	8,174,948	(114,073)	8,289,021
Increase (decrease) in cash and cash equivalents	$ (8,251,884)	$ 4,529,704	$ (12,781,588)

Operating activities:

Net cash provided by operating activities decreased $7,164,208 during 2021, as compared to 2020, primarily the result of the following:

- Increased net payments on derivative contracts of $16,034,880;
- Decreased lease bonus receipts of $260,295;
- Decreased payments for interest expense of $285,825;
- Decreased payments for G&A and other expense of $844,387;
- Decreased field operating expenses of $1,067,442;
- Increased income tax receipts of $48,950; and
- Receipts of natural gas, oil and NGL sales (net of production taxes and gathering, transportation and marketing costs) and other increased $6,884,363.

Investing activities:

Net cash used in investing activities increased $13,906,401 during 2021, as compared to 2020, primarily as the result of the following:

- Higher workover activity during 2021 increased our capital expenditures by $330,036;
- Higher acquisition activity increased our expenditures by $10,336,097; and
- Lower proceeds received from the sale of assets of $3,240,268.

Financing activities:

Net cash provided by financing activities increased $8,289,021 during 2021, as compared to 2020, primarily as a result of the following:

- Increased cash receipts from off-market derivative contracts of $8,800,000 during 2021;
- Increased net proceeds from equity issuance of $3,467,411 during 2021;
- Decreased dividend payments by $591,716 during 2021;
- Increased net payments on debt of $4,575,000.

Capital Resources

We had no capital expenditures to drill and complete wells in 2021, as a result of our strategy to cease participating in new wells with a working interest at the end of fiscal year 2019. We currently have no remaining commitments that would require significant capital to drill and complete wells.

Since we have decided to cease further participation in wells with a working interest on our mineral and leasehold acreage, we anticipate that capital expenditures for working interest properties will be minimal going forward, as the expenditures will be limited to capital workovers to enhance existing wells.

On October 8, 2020, we closed on the purchase of 297 net royalty acres in Grady County, Oklahoma, and 386 net royalty acres in Harrison, Panola and Nacogdoches Counties, Texas, for a purchase price of $5.5 million and 153,375 shares of our Common Stock, subject to customary closing adjustments. This purchase was mostly funded with cash from an underwritten public offering of 5,750,000 shares of our Common Stock that closed on September 1, 2020.

On November 12, 2020, we closed on the purchase of 184 net mineral acres in San Augustine County, Texas for a purchase price of $750,000.

On December 17, 2020, we closed on the purchase of an additional 142 net royalty acres in San Augustine County, Texas, for a purchase price of $1 million.

On April 20, 2021, we completed an underwritten public offering of 6,175,000 common shares (inclusive of overallotment option which closed on April 23, 2021) with net proceeds of approximately $11.1 million.

On April 30, 2021, we closed on the acquisition of certain mineral and royalty assets located in Stephens, Carter, Canadian, McClain, Murray and Garvin Counties, Oklahoma, with the consideration consisting of approximately $8.5 million in cash and 1,200,000 shares of our Common Stock. This acquisition included mineral and royalty assets totaling approximately 2,514 net royalty acres in the SCOOP. The acquisition had an effective date of November 1, 2020.

On June 23, 2021, we closed on the purchase of 131 net royalty acres in the Haynesville for a purchase price of $1 million.

On June 30, 2021, we closed on the purchase of 262 net royalty acres in the Haynesville for a purchase price of $1.3 million.

On September 24, 2021, pursuant to two separate Purchase and Sale Agreements (the "Purchase Agreements"), we closed on the purchase of mineral and royalty assets totaling approximately 817 net royalty acres in the Haynesville, with the consideration comprised of $728,214 in cash and 2,349,207 shares of our Common Stock. A portion of the Common Stock consideration is being held in escrow to satisfy potential indemnity claims arising under the Purchase Agreements. To the extent not returned to us in connection with indemnity claims or to the extent not held in connection with any unresolved indemnity claims, the shares held in escrow will be released to the sellers approximately six months after the closing date. One of the Purchase Agreements included registration rights relating to the Common Stock consideration and, pursuant to such registration rights, we registered the shares with the SEC.

We received lease bonus payments during fiscal year 2021 totaling approximately $0.4 million. Looking forward, the cash flow from bonus payments associated with the leasing of drilling rights on our mineral acreage is difficult to project as the current economic downturn has decreased demand for new leasing by operators. However, management plans to continue to actively pursue leasing opportunities.

With continued natural gas and oil price volatility, management continues to evaluate opportunities for product price protection through additional hedging of our future natural gas and oil production. See Note 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for a complete list of our outstanding derivative contracts.

The use of cash provided by operating activities and resultant change to cash is summarized in the table below:

	Twelve months ended 9/30/2021
Cash provided by operating activities	$ 3,942,087
Cash used for (provided by):	
Capital expenditures - acquisitions	20,624,347
Capital expenditures - drilling, completion and workover of wells	733,172
Quarterly dividends of $0.01 per share	1,060,448
Treasury stock purchases	2,741
Net payments (borrowings) on credit facility	11,250,000
Proceeds from sales of assets	(988,600)
Cash (receipts from) payments on off-market derivative contracts	(8,800,000)
Net proceeds from equity issuance	(11,688,137)
Net cash used	12,193,971
Net increase (decrease) in cash	$ (8,251,884)

Outstanding borrowings under our Credit Facility at September 30, 2021, were $17,500,000. As of December 1, 2021, outstanding borrowings were $17,500,000.

Looking forward, we expect to fund overhead costs, mineral and royalty acquisitions, and dividend payments from cash provided by operating activities, cash on hand and borrowings from our Credit Facility. We had availability of $10,000,000 at September 30, 2021, under our Credit Facility and were in compliance with our debt covenants (current ratio, debt to trailing 12-month EBITDAX, as defined in the Credit Agreement, and restricted payments limited by leverage ratio). The debt covenants in the Credit Agreement limit the maximum ratio of our debt to EBITDAX to no more than 3.5:1.

On September 1, 2021, we entered into the Credit Agreement, which has an initial borrowing base of $27,500,00. The Credit Agreement provides for up to $100 million in borrowings from time to time by the Company and will mature on September 1, 2025. The Credit Agreement replaced our prior revolving credit facility, which was with a lending syndicate led by Bank of Oklahoma. Interest on the Credit Agreement will be calculated based on either (a) LIBOR plus an applicable margin ranging from 2.750% to 3.750% per annum based on our Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on our Borrowing Base Utilization. Under the terms of the Credit Agreement, a 5% interest penalty may apply to any outstanding amount not paid when due or that remains outstanding while an event of default exists. The Credit Agreement contains financial and various other covenants that are common in such agreements, including a (a) maximum ratio of consolidated Funded Indebtedness to consolidated pro forma EBITDAX of 3.50 to 1.00, calculated on a rolling four-quarter basis, and (b) minimum ratio of consolidated Current Assets to consolidated Current Liabilities (excluding the Loan Balance) of 1.00 to 1.00. Other negative covenants include restrictions on our ability to incur debt, grant liens, make fundamental changes and engage in certain transactions with affiliates. The Credit Agreement also restricts our ability to make certain restricted payments if both before and after the Restricted Payment (i) the Available Commitment is less than or equal to ten percent (10%) of the Borrowing Base or (ii) the Leverage Ratio on a pro forma basis is greater than 2.50 to 1.00. All capitalized terms in this description of the Credit Facility that are not otherwise defined in this Annual Report shall have the meaning assigned to them in the Credit Agreement.

Based on our expected capital expenditure levels, anticipated cash provided by operating activities for 2022, combined with availability under our Credit Facility and potential future sales of Common Stock under our currently effective shelf registration statement, including pursuant to the ATM Agreement described below, we have sufficient liquidity to fund our ongoing operations.

On August 25, 2021, we entered into an At-The-Market Equity Offering Sales Agreement (the "ATM Agreement") with Stifel, Nicolaus & Company, Incorporated, as sales agent and/or principal ("Stifel"), pursuant to which we may offer and sell, from time to time through or to Stifel, up to 3,000,000 shares of our Common Stock. As of September 30, 2021, we have sold 221,000 shares of Common Stock pursuant to the ATM Agreement for proceeds of approximately $0.7 million, net of commissions paid.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

We have our Credit Facility with certain lenders and Independent Bank, as Administrative Agent and Letter of Credit Issuer, which provides for up to $100 million in borrowings from time to time and is subject to an at least semi-annual borrowing base determination. The borrowing base at September 30, 2021, was $27,500,000 and all obligations under the Credit Agreement are secured, subject to permitted liens and other exceptions, by a first-priority security interest on substantially all of our personal property and at least 80% of the total value of our proved, developed and producing Oil and Gas Properties. The revolving loan matures on September 1, 2025. Borrowings under the revolving loan are due at maturity. Interest on the Credit Agreement is calculated based on either (a) LIBOR plus an applicable margin ranging from 2.750% to 3.750% per annum based on our Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on our Borrowing Base Utilization. Under the terms of the Credit Agreement, a 5% interest penalty may apply to any outstanding amount not paid when due or that remains outstanding while an event of default exists. At September 30, 2021, the effective rate was 3.75%. All capitalized terms in this description of the Credit Facility that are not otherwise defined in this Annual Report shall have the meaning assigned to them in the Credit Agreement.

Determinations of the borrowing base are made at least semi-annually (on December 1 and June 1) or whenever the banks, in their discretion, believe that there has been a material change in the value of the natural gas and oil properties. The Credit Agreement contains financial and various other covenants that are common in such agreements, including a (a) maximum ratio of consolidated Funded Indebtedness to consolidated pro forma EBITDAX of 3.50 to 1.00, calculated on a rolling four-quarter basis, and (b) minimum ratio of consolidated Current Assets to consolidated Current Liabilities (excluding the Loan Balance) of 1.00 to 1.00. Other negative covenants include restrictions on our ability to incur debt, grant liens, make fundamental changes, and engage in certain transactions with affiliates. The Credit Agreement also restricts our ability to make certain restricted payments if before or after the Restricted Payment (i) the Available Commitment is less than or equal to ten percent (10%) of the Borrowing Base or (ii) the Leverage Ratio on a pro forma basis is greater than 2.50 to 1.00. At September 30, 2021, we were in compliance with the covenants of the Credit Facility, had $17,500,000 outstanding and had $10,000,000 of borrowing base availability under the Credit Facility.

The table below summarizes our contractual obligations and commitments as of September 30, 2021:

	Payments due by period				
Contractual Obligations and Commitments	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-term debt obligations	$17,500,000	$ -	$ -	$ 17,500,000	$ -
Building lease	$ 1,039,225	$ 166,744	$ 342,996	$ 360,547	$ 168,938

Our building lease is accounted for as an operating lease, and a related operating lease right-of-use asset and operating lease liability has been recognized on our balance sheets.

At September 30, 2021, our derivative contracts were in a net liability position of $13,784,467. The ultimate settlement amounts of the derivative contracts are unknown because they are subject to continuing market risk. Please read Item 7A – "Quantitative and Qualitative Disclosures about Market Risk" and Note 12 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding our derivative contracts.

As of September 30, 2021, our estimate for asset retirement obligations was $2,836,172. Asset retirement obligations represent our share of the future expenditures to plug and abandon the wells in which we own a working interest at the end of their economic lives. These amounts were not included in the schedule above due to the uncertainty of timing of the obligations. Please read Note 11 to the financial statements included in Item 8 – "Financial Statements and Supplementary Data" for additional information regarding our asset retirement obligations.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements during 2021 and 2020, and we currently do not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on our financial condition, or result in changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

CRITICAL ACCOUNTING POLICIES

Preparation of financial statements in conformity with GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by the Company generally do not change our reported cash flows or liquidity. Existing rules must be interpreted, and judgments made on how the specifics of a given rule apply to the Company.

The more significant reporting areas impacted by management's judgments and estimates include: natural gas, crude oil and NGL reserve estimation; derivative contracts; impairment of assets; natural gas, oil and NGL sales revenue accruals; and provision for income taxes. Management's judgments and estimates are based on information available from both internal and external sources, including engineers, geologists, consultants and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known. The natural gas, oil and NGL sales revenue accrual is particularly subject to estimate inaccuracies due to our status as a non-operator on all of our properties. As such, production and price information obtained from well operators is substantially delayed. This causes the estimation of recent production and prices used in the natural gas, oil and NGL revenue accrual to be subject to future change.

Natural Gas, Oil and NGL Reserves

Management considers the estimation of our natural gas, crude oil and NGL reserves to be the most significant of our judgments and estimates. These estimates affect the unaudited standardized measure disclosures included in Note 16 to the financial statements in Item 8 – "Financial Statements and Supplementary Data" as well as DD&A and impairment calculations for working interest properties. Changes in natural gas, crude oil and NGL reserve estimates affect our calculation of DD&A, asset retirement obligations and assessment of the need for asset impairments. Our Independent Consulting Petroleum Engineer, with assistance from Company staff, prepares our estimates of natural gas, crude oil and NGL reserves on an annual basis, with a semi-annual update. These estimates are based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. Between periods in which reserves would normally be calculated, we update the reserve calculations utilizing prices which are updated through the current period. In accordance with SEC rules, our reserve estimates were based on average individual product prices during the 12-month period prior to September 30 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. Based on our 2021 DD&A, a 10% change in the DD&A rate per Mcfe would result in a corresponding $774,580 annual change in DD&A expense. Natural gas, crude oil and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future natural gas, crude oil and NGL pricing assumptions are used by management to prepare estimates of natural gas, crude oil and NGL reserves and future net cash flows used in asset impairment assessments and in formulating management's overall operating decisions.

Successful Efforts Method of Accounting

We have elected to utilize the successful efforts method of accounting for our natural gas and oil exploration and development activities. This means exploration expenses, including geological and geophysical costs, non-producing lease impairment, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized by property using the unit-of-production method for working interest wells (the ratio of natural gas, oil and NGL volumes produced to total proved or proved developed reserves is used to amortize the remaining asset basis on each producing property) as natural gas, oil and NGL is produced. Our exploratory wells are all onshore in the continental United States and primarily located in the Mid-Continent area. Generally, expenditures on exploratory wells comprise less than 5% of our total expenditures for natural gas and oil properties. This accounting method may yield significantly different operating results than the full cost method.

Derivative Contracts

We have entered into costless collar contracts and fixed swap contracts. These instruments are intended to reduce our exposure to short-term fluctuations in the price of natural gas and oil. Collar contracts set a fixed floor price and a fixed ceiling price and provide payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide for payments to the Company if the index price is below the fixed price or require payments by the Company if the index price is above the fixed price. These contracts cover only a portion of our natural gas and oil production, provide only partial price protection against declines in natural gas and oil prices and may limit the benefit of future increases in prices. Our derivative contracts are with BP. The derivative contracts with BP are secured under our Credit Facility.

We are required to recognize all derivative instruments as either assets or liabilities in the balance sheet at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. At September 30, 2021, we had no derivative contracts designated as cash flow hedges, and therefore, changes in the fair value of derivatives are reflected in earnings.

Impairment of Assets

All long-lived assets, principally natural gas and oil properties, are monitored for potential impairment when circumstances indicate that the carrying value of the asset may be greater than our estimated future net cash flows. The evaluations involve significant judgment, since the results are based on estimated future events, such as: inflation rates; future sales prices for natural gas, oil and NGL; future production costs; estimates of future natural gas, oil and NGL reserves to be recovered and the timing thereof; economic and regulatory climates and other factors. We estimate future net cash flows on our natural gas and oil properties utilizing differentially adjusted forward pricing curves for natural gas, oil and NGL and a discount rate in line with the discount rate we believe is most commonly used by market participants (10% for all periods presented). The need to test a property for impairment may result from significant declines in sales prices or unfavorable adjustments to natural gas, oil and NGL reserves. A further reduction in natural gas, oil and NGL prices (which are reviewed quarterly) or a decline in reserve volumes (which are re-evaluated semi-annually) would likely lead to additional impairment that may be material to the Company. The decision to not participate in future development on our leasehold acreage can trigger a test for impairment. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Natural Gas, Oil and NGL Sales Revenue Accrual

We do not operate our natural gas and oil properties and, therefore, receive actual natural gas, oil and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, on wells with greater significance to the Company, the most current available production data is gathered from the appropriate operators, as well as public and private sources, and natural gas, oil and NGL index prices local to each well are used to estimate the accrual of revenue on these wells. Obtaining timely production data on all other wells from the operators is not feasible; therefore, we utilize past production receipts and estimated sales price information to estimate our accrual of revenue on all other wells each quarter. The natural gas, oil and NGL sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for natural gas, oil and NGL. These variables could lead to an over or under accrual of natural gas, oil and NGL sales at the end of any particular quarter. Based on past history, our estimated accruals have been materially accurate.

Income Taxes

The estimation of the amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations, as well as the completion of complex calculations, including the determination of our percentage depletion deduction, if any. To calculate the exact excess percentage depletion allowance, a well-by-well calculation is, and can only be, performed at the end of each fiscal year. During interim periods, an estimate is made which takes into account historical data and current pricing. We have certain state and federal net operating loss carry forwards (NOLs) that are recognized as tax assets when assessed as more likely than not to be utilized before their expiration dates. Criteria such as expiration dates, future excess state depletion and reversing taxable temporary differences are evaluated to determine whether the NOLs are more likely than not to be utilized before they expire. If any NOLs are no longer determined to be more likely than not to be utilized, then a valuation allowance is recognized to reduce the tax benefit of such NOLs.

The above description of our critical accounting policies is not intended to be an all-inclusive discussion of the uncertainties considered and estimates made by management in applying GAAP. Results may vary significantly if different policies were used or required and if new or different information becomes known to management.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Natural gas, oil and NGL prices historically have been volatile, and this volatility is expected to continue. Uncertainty continues to exist as to the direction of natural gas, oil and NGL price trends, and there remains a wide divergence in the opinions held in the industry. We can be significantly impacted by changes in natural gas and oil prices. The market price of natural gas, oil and NGL in 2022 will impact the amount of cash generated from operating activities, which will in turn impact the level of our capital expenditures for acquisitions and production. Excluding the impact of our 2022 derivative contracts (see below), the price sensitivity for each $0.10 per Mcf change in wellhead natural gas price is approximately $669,972 for operating revenue based on our prior year natural gas volumes. The price sensitivity in 2022 for each $1.00 per barrel change in wellhead oil is approximately $224,479 for operating revenue based on our prior year oil volumes.

Financial Market Risk

Operating income could also be impacted, to a lesser extent, by changes in the market interest rates related to our Credit Facility. Interest under our Credit Facility is calculated based on either (a) LIBOR plus an applicable margin ranging from 2.750% to 3.750% per annum based on our Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on our Borrowing Base Utilization. Under the terms of the Credit Agreement, a 5% interest penalty may apply to any outstanding amount not paid when due or that remains outstanding while an event of default exists. At September 30, 2021, we had $17,500,000 outstanding under this facility and the effective interest rate was 3.75%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of $175,000 for the year ended September 30, 2021, assuming that our indebtedness remained constant throughout the period. At this point, we do not believe that our liquidity has been materially affected by the debt market uncertainties noted in the last few years, and we do not believe that our liquidity will be significantly impacted in the near future. All capitalized terms in this description of the interest rate under the Credit Facility that are not otherwise defined in this Annual Report shall have the meaning assigned to them in the Credit Agreement.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of PHX Minerals Inc.

Opinion on Internal Control Over Financial Reporting

We have audited PHX Minerals Inc.'s internal control over financial reporting as of September 30, 2021, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, because of the effect of the material weakness described below on the achievement of the objectives of the control criteria, PHX Minerals Inc. (the Company) has not maintained effective internal control over financial reporting as of September 30, 2021, based on the COSO criteria.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weakness has been identified and included in management's assessment. Management has identified a material weakness in one of the Company's internal controls related to the review of the annual income tax provision prepared by a third-party firm. Specifically, the Company's review of the annual income tax provision did not include a process to sufficiently evaluate deferred tax assets to determine if a valuation allowance was necessary.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the balance sheets of the Company as of September 30, 2021 and 2020, the related statements of operations, stockholders' equity and cash flows for each of the three years in the period ended September 30, 2021, and the related notes. This material weakness was considered in determining the nature, timing and extent of audit tests applied in our audit of the 2021 financial statements, and this report does not affect our report dated December 13, 2021 which expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
December 13, 2021

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of PHX Minerals Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of PHX Minerals Inc. (the Company) as of September 30, 2021 and 2020, the related statements of operations, stockholders' equity and cash flows for each three years in the period ended September 30, 2021, 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 at September 30, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2021, in conformity with U.S. generally accepted accounting principles.

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 September 30, 2021, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated December 13, 2021 expressed an adverse opinion thereon.

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 audits 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 the critical audit matter 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 a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

	Depreciation, Depletion and Amortization of Producing Oil and Natural Gas Properties
Description of the Mater	At September 30, 2021, the net book value of the Company's oil and natural gas properties was $104 million, and depreciation, depletion and amortization ("DD&A") expense related to the Company's producing and non-producing oil and natural gas properties was $7.7 million. As discussed in Note 1, the Company follows the successful efforts method of accounting for its oil and gas natural gas producing activities. DD&A on producing properties is recorded based on the units-of-production method on an individual property basis using proved or proved developed reserves, as applicable, as estimated by the Company's Independent Consulting Petroleum Engineers. Proved oil and natural gas reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. The Company's Independent Consulting Petroleum Engineer, with assistance from the Company, prepares estimates of natural gas, crude oil and NGL reserves. These estimates are based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. For DD&A purposes, the reserve estimates are based on average individual product prices during the 12-month period prior to September 30, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such

period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. Natural gas, crude oil and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management.

Significant judgment is required by the Independent Consulting Petroleum Engineers in evaluating geological and engineering data used to estimate oil and natural gas reserves. Estimating reserves also requires the selection of inputs, including oil and natural gas price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Auditing the Company's DD&A calculations is especially complex because of the use of the work of the Independent Petroleum Consulting Engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved developed oil and natural gas reserves.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of internal controls over the Company's process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating proved developed oil and natural gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Independent Petroleum Consulting Engineers used to prepare the oil and natural gas reserve estimates. In addition, in assessing whether we can use the work of the Independent Petroleum Consulting Engineers we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating proved oil and natural gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved developed oil and natural gas reserve amounts used in the calculations to the Company's reserve report.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1989.
Oklahoma City, Oklahoma
December 13, 2021

PHX Minerals Inc.
Balance Sheets

	September 30, 2021	September 30, 2020
Assets		
Current Assets:		
Cash and cash equivalents	$ 2,438,511	$ 10,690,395
Natural gas, oil and NGL sales receivables (net of $0 allowance for uncollectable accounts)	6,428,982	2,943,220
Refundable income taxes	2,413,942	3,805,227
Other	942,082	351,088
Total current assets	12,223,517	17,789,930
Properties and equipment at cost, based on successful efforts accounting:		
Producing natural gas and oil properties	319,984,874	324,886,491
Non-producing natural gas and oil properties	40,466,098	18,993,814
Other	794,179	582,444
	361,245,151	344,462,749
Less accumulated depreciation, depletion and amortization	(257,643,661)	(263,590,801)
Net properties and equipment	103,601,490	80,871,948
Investments	308	79,308
Operating lease right-of-use assets	607,414	690,316
Other, net	578,285	590,333
Total assets	$ 117,011,014	$ 100,021,835
Liabilities and Stockholders' Equity		
Current Liabilities:		
Accounts payable	$ 772,717	$ 997,637
Derivative contracts, net	12,087,988	281,942
Current portion of operating lease liability	132,287	127,108
Income taxes payable	334,050	-
Accrued liabilities and other	1,809,337	1,297,363
Short-term debt	-	1,750,000
Total current liabilities	15,136,379	4,454,050
Long-term debt	17,500,000	27,000,000
Deferred income taxes	343,906	1,329,007
Asset retirement obligations	2,836,172	2,897,522
Derivative contracts, net	1,696,479	425,705
Operating lease liability, net of current portion	789,339	921,625
Total liabilities	38,302,275	37,027,909
Stockholders' equity:		
Class A voting common stock, par value $0.01666 per share: 36,000,500 shares authorized and 32,770,433 shares issued and outstanding at September 30, 2021; 24,000,500 shares authorized and 22,647,306 shares issued and outstanding at September 30, 2020	545,956	377,304
Capital in excess of par value	33,213,645	10,649,611
Deferred directors' compensation	1,768,151	1,874,007
Retained earnings	48,966,420	56,244,100
	84,494,172	69,145,022
Treasury stock, at cost: 388,545 shares at September 30, 2021; 411,487 shares at September 30, 2020	(5,785,433)	(6,151,096)
Total stockholders' equity	78,708,739	62,993,926
Total liabilities and stockholders' equity	$ 117,011,014	$ 100,021,835

See accompanying notes.

PHX Minerals Inc.
Statements of Operations

	Year ended September 30, 2021	2020	2019
Revenues:			
Natural gas, oil and NGL sales	$ 37,749,044	$ 23,370,003	$ 39,410,036
Lease bonuses and rental income	425,113	690,961	1,547,078
Gains (losses) on derivative contracts (Note 12)	(16,202,489)	907,419	6,105,145
	21,971,668	24,968,383	47,062,259
Costs and expenses:			
Lease operating expenses	4,230,968	4,841,541	6,398,522
Transportation, gathering and marketing	5,767,287	4,812,869	6,089,903
Production taxes	1,938,304	1,022,912	1,902,636
Depreciation, depletion and amortization	7,745,804	11,313,783	18,196,583
Provision for impairment	50,475	29,904,528	76,824,337
Interest expense	995,127	1,286,788	1,995,789
General and administrative	8,207,882	8,024,901	8,565,243
Loss on debt extinguishment	260,236	-	-
Losses (gains) on asset sales and other	(356,127)	(3,997,902)	(18,684,816)
	28,839,956	57,209,420	101,288,197
Income (loss) before provision (benefit) for income taxes	(6,868,288)	(32,241,037)	(54,225,938)
Provision (benefit) for income taxes	(651,051)	(8,289,000)	(13,481,000)
Net income (loss)	$ (6,217,237)	$ (23,952,037)	$ (40,744,938)
Basic and diluted earnings (loss) per common share (Note 4)	$ (0.24)	$ (1.41)	$ (2.43)

See accompanying notes.

PHX Minerals Inc.
Statements of Stockholders' Equity

	Class A voting Common Stock Shares	Class A voting Common Stock Amount	Capital in Excess of Par Value	Deferred Directors' Compensation	Retained Earnings	Treasury Shares	Treasury Stock	Total
Balances at September 30, 2018	16,896,881	$281,502	$ 2,824,691	$ 2,950,405	$125,266,945	(145,467)	$(2,558,338)	$128,765,205
Net income (loss)	-	-	-	-	(40,744,938)	-	-	(40,744,938)
Purchase of treasury stock	-	-	-	-	-	(515,972)	(7,454,000)	(7,454,000)
Issuance of treasury shares to ESOP	-	-	(25,830)	-	-	26,629	398,104	372,274
Restricted stock awards	-	-	771,797	-	-	-	-	771,797
Dividends declared ($0.16 per share)	-	-	-	-	(2,673,706)	-	-	(2,673,706)
Distribution of restricted stock to officers and directors	425	7	(394,824)	-	-	24,360	395,230	413
Distribution of deferred directors' compensation	-	-	(207,850)	(667,115)	-	52,399	874,962	(3)
Common shares to be issued to directors for services	-	-	-	272,491	-	-	-	272,491
Balances at September 30, 2019	16,897,306	$281,509	$ 2,967,984	$ 2,555,781	$ 81,848,301	(558,051)	$(8,344,042)	$ 79,309,533
Net income (loss)	-	-	-	-	(23,952,037)	-	-	(23,952,037)
Purchase of treasury stock	-	-	-	-	-	(632)	(7,635)	(7,635)
Issuance of treasury shares to ESOP	-	-	(974,806)	-	-	72,101	1,077,910	103,104
Restricted stock awards	-	-	743,897	-	-	-	-	743,897
Dividends declared ($0.10 per share)	-	-	-	-	(1,652,164)	-	-	(1,652,164)
Distribution of restricted stock to officers and directors	-	-	(82,820)	-	-	5,546	82,914	94
Distribution of deferred directors' compensation	-	-	(129,575)	(910,182)	-	69,549	1,039,757	-
Common shares to be issued to directors for services	-	-	-	228,408	-	-	-	228,408
Equity offering	5,750,000	95,795	8,124,931	-	-	-	-	8,220,726
Balances at September 30, 2020	22,647,306	$377,304	$10,649,611	$ 1,874,007	$ 56,244,100	(411,487)	$(6,151,096)	$ 62,993,926
Net income (loss)	-	-	-	-	(6,217,237)	-	-	(6,217,237)
Purchase of treasury stock	-	-	-	-	-	(1,229)	(2,741)	(2,741)
Restricted stock awards	-	-	801,200	-	-	-	-	801,200
Dividends declared ($0.04 per share)	-	-	-	-	(1,060,443)	-	-	(1,060,443)
Distribution of restricted stock to officers and directors	-	-	(369,260)	-	-	24,171	368,404	(856)
Distribution of deferred directors' compensation	24,545	410	339,913	(340,322)	-	-	-	1
Increase in deferred directors' compensation charged to expense	-	-	-	234,466	-	-	-	234,466
Equity offering	9,877,582	164,560	21,196,584	-	-	-	-	21,361,144
At-the-market offering	221,000	3,682	595,597	-	-	-	-	599,279
Balances at September 30, 2021	32,770,433	$545,956	$33,213,645	$ 1,768,151	$ 48,966,420	(388,545)	$(5,785,433)	$ 78,708,739

See accompanying notes.

PHX Minerals Inc.
Statements of Cash Flows

	Year ended September 30,		
	2021	2020	2019
Operating Activities			
Net income (loss)	$ (6,217,237)	$ (23,952,037)	$ (40,744,938)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	7,745,804	11,313,783	18,196,583
Impairment of producing properties	50,475	29,904,528	76,824,337
Provision for deferred income taxes	(985,101)	(4,647,000)	(12,112,000)
Gain from leasing fee mineral acreage	(421,915)	(685,927)	(1,546,298)
Proceeds from leasing fee mineral acreage	441,653	701,948	1,565,649
Net (gain) loss on sales of assets	(309,348)	(3,973,321)	(18,730,197)
ESOP contribution expense	-	103,104	372,274
Directors' deferred compensation expense	234,466	228,408	272,491
Total (gain) loss on derivative contracts	16,202,489	(907,419)	(6,105,145)
Cash receipts (payments) on settled derivative contracts	(11,925,669)	4,109,210	196,985
Restricted stock awards	801,200	743,897	771,797
Loss on debt extinguishment	260,236	-	-
Other	(11,099)	(2,611)	19,085
Cash provided (used) by changes in assets and liabilities:			
Natural gas, oil and NGL sales receivables	(3,485,762)	1,434,426	2,723,983
Refundable income taxes	1,391,285	(2,299,785)	(1,472,277)
Other current assets	(436,401)	(89,931)	21,116
Accounts payable	(151,875)	1,308,731	105,217
Other non-current assets	(86,282)	(1,044,680)	7,166
Accrued liabilities	845,168	(1,139,029)	639,856
Total adjustments	10,159,324	35,058,332	61,750,622
Net cash provided by operating activities	3,942,087	11,106,295	21,005,684
Investing Activities			
Capital expenditures	$ (733,172)	$ (403,136)	$ (3,526,007)
Acquisition of minerals and overriding royalty interests	(20,624,347)	(10,288,250)	(5,662,869)
Investments in partnerships	-	-	(1,648)
Proceeds from sales of assets	988,600	4,228,868	19,515,735
Net cash provided (used) by investing activities	(20,368,919)	(6,462,518)	10,325,211
Financing Activities			
Borrowings under Credit Facility	26,300,000	6,061,725	16,642,481
Payments of loan principal	(37,550,000)	(12,736,725)	(32,217,481)
Net proceeds from equity issuance	11,688,137	8,220,726	-
Cash receipts from (payments on) off-market derivative contracts	8,800,000	-	-
Purchases of treasury stock	(2,741)	(7,635)	(7,454,000)
Payments of dividends	(1,060,448)	(1,652,164)	(2,673,706)
Net cash provided (used) by financing activities	8,174,948	(114,073)	(25,702,706)
Increase (decrease) in cash and cash equivalents	(8,251,884)	4,529,704	5,628,189
Cash and cash equivalents at beginning of year	10,690,395	6,160,691	532,502
Cash and cash equivalents at end of year	$ 2,438,511	$ 10,690,395	$ 6,160,691
Supplemental Disclosures of Cash Flow Information			
Interest paid (net of capitalized interest)	$ 1,021,142	$ 1,306,967	$ 2,031,762
Income taxes paid (net of refunds received)	$ (1,391,225)	$ (1,342,275)	$ 103,279
Supplemental schedule of noncash investing and financing activities:			
Additions and revisions, net, to asset retirement obligations	$ -	$ 4	$ 27,782
Gross additions to properties and equipment	$ 31,485,015	$ 10,701,284	$ 9,248,415
Equity offering used for acquisitions	(10,272,288)	-	-
Net (increase) decrease in accounts payable for properties and equipment additions	144,792	(9,898)	(59,539)
Capital expenditures, including dry hole costs	$ 21,357,519	$ 10,691,386	$ 9,188,876

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

The Company's principal line of business is maximizing the value of its existing mineral and royalty assets through active management and expanding its asset base through acquisitions of additional mineral and royalty interests. The Company owns mineral and leasehold properties and other natural gas and oil interests, which are all located in the contiguous United States, primarily in Oklahoma, Texas, Louisiana, North Dakota and Arkansas, with properties located in several other states. The Company's natural gas, oil and NGL production is from interests in 6,457 wells located principally in Oklahoma, Texas, Arkansas and North Dakota. The Company does not operate any wells. Approximately 56%, 34% and 10% of natural gas, oil and NGL revenues were derived from the sale of natural gas, oil and NGL, respectively, in 2021. Approximately 74%, 15% and 11% of the Company's total sales volumes in 2021 were derived from natural gas, oil and NGL, respectively. Substantially all the Company's natural gas, oil and NGL production is sold through the operators of the wells.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, management considers the estimation of natural gas, crude oil and NGL reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as DD&A and impairment calculations. The Company's Independent Consulting Petroleum Engineer, with assistance from the Company, prepares estimates of natural gas, crude oil and NGL reserves on an annual basis, with a semi-annual update. These estimates are based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. For DD&A purposes, and as required by the guidelines and definitions established by the SEC, the reserve estimates were based on average individual product prices during the 12-month period prior to September 30, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. For impairment purposes, projected future natural gas, crude oil and NGL prices as estimated by management are used. Natural gas, crude oil and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Management uses projected future natural gas, crude oil and NGL pricing assumptions to prepare estimates of natural gas, crude oil and NGL reserves used in formulating management's overall operating decisions.

As a non-operator of working, royalty and mineral interests, the Company receives actual natural gas, oil and NGL sales volumes and prices more than a month after the information is available to the operators of the wells. Because of the delay in information, the most current available production data is gathered from the appropriate operators, as well as public and private sources, and natural gas, oil and NGL index prices local to each well are used to estimate the accrual of revenue on these wells. If information is not available from an outside source, the Company utilizes past production receipts and estimated sales price information to estimate its accrual of revenue on all other wells each quarter. The natural gas, oil and NGL sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for natural gas, oil and NGL. These variables could lead to an over or under accrual of natural gas, oil and NGL at the end of any particular quarter. Based on past history, the Company's estimated accrual has been materially accurate.

Basis of Presentation

Certain reclassifications have been made to prior period financials to conform to the current year presentation. These reclassifications have no impact on previous reported total assets, total liabilities, net loss, stockholders' equity, or operating cash flows.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in short-term investments with original maturities of three months or less.

Natural Gas, Oil and NGL Sales

The Company sells natural gas, oil and NGL to various customers, recognizing revenues as natural gas, oil and NGL is produced and sold.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Company's accounts receivable are due from purchasers (operators) of natural gas, oil and NGL. Natural gas, oil and NGL sales receivables are generally unsecured. This industry concentration has the potential to impact our overall exposure to credit risk, in that the purchasers of our natural gas, oil and NGL and the operators of the properties in which we have an interest may be similarly affected by changes in economic, industry or other conditions. During 2021, 2020 and 2019 the Company did not have any bad debt expense. The Company's allowance for uncollectible accounts as of the balance sheet dates was not material.

Natural Gas and Oil Producing Activities

The Company follows the successful efforts method of accounting for natural gas and oil producing activities. For working interest properties, intangible drilling and other costs of successful wells and development dry holes are capitalized and amortized. The costs of exploratory wells are initially capitalized, but charged against income, if and when the well does not reach commercial production levels. Natural gas and oil mineral and leasehold costs are capitalized when incurred.

Leasing of Mineral Rights

The Company generates lease bonuses by leasing its mineral interests to exploration and production companies. A lease agreement represents the Company's contract with a third party and generally conveys the rights to any natural gas, oil or NGL discovered, grants the Company a right to a specified royalty interest and requires that drilling and completion operations commence within a specified time period. Control is transferred to the lessee and the Company has satisfied its performance obligation when the lease agreement is executed, such that revenue is recognized when the lease bonus payment is received. The Company accounts for its lease bonuses as conveyances in accordance with the guidance set forth in ASC 932, and it recognizes the lease bonus as a cost recovery with any excess above its cost basis in the mineral being treated as income. The excess of lease bonus above the mineral basis is shown in the lease bonuses and rentals line item on the Company's Statements of Operations.

Derivatives

The Company utilizes derivative contracts to reduce its exposure to short-term fluctuations in the price of natural gas and oil. These derivatives are recorded at fair value on the balance sheet. The Company has elected not to complete the documentation requirements necessary to permit these derivative contracts to be accounted for as cash flow hedges.

Properties and Equipment

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization of the costs of producing natural gas and oil properties are generally computed using the unit-of-production method primarily on an individual property basis using proved or proved developed reserves, as applicable, as estimated by the Company's Independent Consulting Petroleum Engineer. The Company's capitalized costs of drilling and equipping all development wells, and those exploratory wells that have found proved reserves, are amortized on a unit-of-production basis over the remaining life of associated proved developed reserves. Leasehold costs for working interest properties are amortized on a unit-of-production basis over the remaining life of associated total proved reserves. Depreciation of furniture and fixtures is computed using the straight-line method over estimated productive lives of five to eight years.

Non-producing natural gas and oil properties include non-producing minerals, which had a net book value of $32,542,709 and $13,556,020 at September 30, 2021 and 2020, respectively, consisting of perpetual ownership of mineral interests in several states, with 61% of the acreage in Oklahoma, Texas, Louisiana, North Dakota and Arkansas. As mentioned, these mineral rights are perpetual and have been accumulated over the 95-year life of the Company. There are approximately 187,386 net acres of non-producing minerals in more than 6,309 tracts owned by the Company. An average tract contains approximately 30 acres. Since inception, the Company has continually generated an interest in several thousand natural gas and oil wells using its ownership of the fee mineral acres as an ownership basis. There continues to be drilling and leasing activity on these mineral interests each year. Non-producing minerals are considered a long-term investment by the Company, as they do not expire (unlike natural gas and oil leases) and based on past history and experience, management has concluded that a long-term straight-line amortization over 33 years is appropriate. Due to the fact that the Company's mineral ownership consists of a large number of properties, whose costs are not individually significant, and because virtually all are in the Company's core operating areas, the minerals are being amortized on an aggregate basis (by mineral deed).

When a new well is drilled on the Company's mineral acreage, all of the non-producing mineral costs for the associated mineral deed are transferred to producing minerals and are amortized straight-line over a 20-year period (insignificant fields are amortized over a 10-year period). Management has historically chosen to move non-producing mineral costs in this manner, as it is very difficult for the Company, as a non-operator, to predict well spacing and timing of drilling on the Company's minerals, and future development will deplete these assets over a long period. The straight-line amortization over a 20-year period is appropriate for producing minerals, because current and future development will deplete these assets over a fairly long period.

Capitalized Interest

During 2021, 2020 and 2019, interest of $0, $0 and $38,606, respectively, was included in the Company's capital expenditures. Interest of $995,127, $1,286,788 and $1,995,789, respectively, was charged to expense during those periods. Interest is capitalized using a weighted average interest rate based on the Company's outstanding borrowings. These capitalized costs are included with intangible drilling costs and amortized using the unit-of-production method.

Accrued Liabilities

The following table shows the balances for the years ended September 30, 2021 and 2020, relating to the Company's accrued liabilities:

	Year Ended September 30,	
	2021	2020
Accrued compensation	$ 982,259	$ 481,062
Revenues payable	275,981	281,380
Accrued ad valorem	245,116	228,010
Other	305,981	306,911
Total accrued liabilities	$ 1,809,337	$ 1,297,363

The increase in accrued compensation in 2021 is primarily due to the short-term incentive compensation driven by Company performance.

Asset Retirement Obligations

The Company owns interests in natural gas and oil properties, which may require expenditures to plug and abandon the wells upon the end of their economic lives. The fair value of legal obligations to retire and remove long-lived assets is recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, this cost is capitalized by increasing the carrying amount of the related properties and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties and equipment is depreciated over the useful life of the remaining asset. The Company does not have any assets restricted for the purpose of settling asset retirement obligations.

Environmental Costs

As the Company is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays. The Company does not believe the existence of current environmental laws, or interpretations thereof, will materially hinder or adversely affect the Company's business operations; however, there can be no assurances of future effects on the Company of new laws or interpretations thereof. Since the Company does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by the well operators, with the Company being responsible for its proportionate share of the costs involved (on working interest wells only). The Company carries liability and pollution control insurance. However, all risks are not insured due to the availability and cost of insurance.

Environmental liabilities, which historically have not been material, are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At September 30, 2021 and 2020, there were no such costs accrued.

Earnings (Loss) Per Share of Common Stock

Earnings (loss) per share is calculated using net income (loss) divided by the weighted average number of common shares outstanding, plus unissued, vested directors' deferred compensation shares during the period.

Share-based Compensation

The Company recognizes current compensation costs for its Deferred Compensation Plan for Non-Employee Directors (the "Plan"). Compensation cost is recognized for the requisite directors' fees as earned and unissued stock is recorded to each director's account based on the fair market value of the stock at the date earned. The Plan provides that only upon retirement, termination or death of the director or upon a change in control of the Company, the shares accrued under the Plan may be issued to the director.

In accordance with guidance on accounting for employee stock ownership plans, the Company records the fair market value of the stock contributed into its ESOP as expense.

Restricted stock awards to officers provide for cliff vesting at the end of three years from the date of the awards. These restricted stock awards can be granted based on service time only (time-based), subject to certain share price performance standards (market-based) or subject to company performance standards (performance-based). Restricted stock awards to the non-employee directors provide for annual vesting during the calendar year of the award. The fair value of the awards on the grant date is ratably expensed over the vesting period in accordance with accounting guidance.

Income Taxes

The estimation of amounts of income tax to be recorded by the Company involves interpretation of complex tax laws and regulations, as well as the completion of complex calculations, including the determination of the Company's percentage depletion deduction. Although the Company's management believes its tax accruals are adequate, differences may occur in the future depending on the resolution of pending and new tax regulations. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of the Company's assets and liabilities.

The Company's provision for income taxes differs from the statutory rate primarily due to estimated federal and state benefits generated from estimated excess federal and Oklahoma percentage depletion, which are permanent tax benefits. Excess percentage depletion, both federal and Oklahoma, can only be taken in the amount that it exceeds cost depletion which is calculated on a unit-of-production basis.

Both excess federal percentage depletion, which is limited to certain production volumes and by certain income levels, and excess Oklahoma percentage depletion, which has no limitation on production volume, reduce estimated taxable income or add to estimated taxable loss projected for any year. Federal and Oklahoma excess percentage depletion, when a provision for income taxes is expected for the year, decreases the effective tax rate, while the effect is to increase the effective tax rate when a benefit for income taxes is expected for the year. The benefits of federal and Oklahoma excess percentage depletion and excess tax benefits and deficiencies of stock-based compensation are not directly related to the amount of pre-tax income (loss) recorded in a period. Accordingly, in periods where a recorded pre-tax income or loss is relatively small, the proportional effect of these items on the effective tax rate may be significant. The effective tax rate for the year ended September 30, 2021, was a 9% benefit, as compared to a 26% benefit for the year ended September 30, 2020.

The threshold for recognizing the financial statement effect of a tax position is when it is more likely than not, based on the technical merits, that the position will be sustained by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not to be realized upon ultimate settlement with a taxing authority. The Company files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Subject to statutory exceptions that allow for a possible extension of the assessment period, the Company is no longer subject to U.S. federal, state, and local income tax examinations for fiscal years prior to 2018.

The Company includes interest assessed by the taxing authorities in interest expense and penalties related to income taxes in general and administrative expense on its Statements of Operations. For the fiscal years ended September 30, 2021, 2020 and 2019, the Company's interest and penalties were not material. The Company does not believe it has any material uncertain tax positions.

Recent Accounting Pronouncements

Standard	Description	Date of Adoption	Impact on Financial Statements or Other Significant Matters
Adoption of New Accounting Pronouncements			
ASU 2016-02, *Leases (Topic 842)*	This update will supersede the lease requirements in Topic 840, *Leases*, by requiring lessees to recognize lease assets and lease liabilities classified as operating leases on the balance sheet.	Q1 2020	See Note 2: Leases for further details related the Company's adoption of this standard.
ASU 2018-11, *Leases (Topic 842), Targeted Improvements* and ASC 842	This update will allow entities to apply the transition provisions of the new standard at the adoption date instead of at the earliest comparative period presented in the financial statements and will allow entities to continue to apply the legacy guidance in Topic 840, including disclosure requirements, in the comparative period presented in the year the new leases standard is adopted. Entities that elect this option would still adopt the new leases standard using a modified retrospective transition method but would recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if any, rather than in the earliest period presented.	Q1 2020	See Note 2: Leases for further details related the Company's adoption of this standard.
ASU 2016-13, *Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*.	This standard changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost.	Q1 2021	The adoption of this update did not have a material impact on the Company's balance sheet, statement of operations or liquidity. The Company's credit losses on natural gas, oil and NGL sales receivables are immaterial.
New Accounting Pronouncements yet to be Adopted			
ASU 2019-12, *Simplifying the Accounting for Income Taxes*.	This standard is intended to clarify and simplify the accounting for income taxes by removing certain exceptions and amending existing guidance.	Q1 2022	This standard is effective for public business entities for fiscal years beginning after December 15, 2020, with early adoption permitted. The Company is still in the process of assessing the impacts, if any, of adopting this new standard.

2. LEASES AND COMMITMENTS

Assessment of Leases

The Company determines if an arrangement is a lease at inception by considering whether (i) explicitly or implicitly identified assets have been deployed in the agreement and (ii) the Company obtains substantially all of the economic benefits from the use of that underlying asset and directs how and for what purpose the asset is used during the term of the agreement. As of September 30, 2021, none of the Company's leases were classified as financing leases. Operating lease liabilities represent the Company's obligation to make lease payments arising from the lease. The Company signed a new seven-year lease for office space during the quarter ended March 31, 2020, with a commencement date in August 2020. The associated lease liability and ROU asset at September 30, 2021, were $921,626 and $607,414, respectively. The Company has a lease incentive asset of $294,000, which is included in Other, net on the Company's balance sheets.

ROU assets represent the Company's right to use an underlying asset for the lease term, and operating lease liabilities represent the Company's obligation to make payments arising from the lease. ROU assets are recognized at commencement date and consist of the present value of remaining lease payments over the lease term, initial direct costs and prepaid lease payments less any lease incentives. Operating lease liabilities are recognized at commencement date based on the present value of remaining lease payments over the lease term. The Company uses the implicit rate, when readily determinable, or its incremental borrowing rate based on the information available at commencement date to determine the present value of lease payments.

The lease terms may include periods covered by options to extend the lease when it is reasonably certain that the Company will exercise that option and periods covered by options to terminate the lease when it is not reasonably certain that the Company will exercise that option. Lease expense for lease payments will be recognized on a straight-line basis over the lease term. The Company made an accounting policy election to not recognize leases with terms, including applicable options, of less than twelve months on the Company's balance sheets and recognize those lease payments in the Company's Statements of Operations on a straight-line basis over the lease term. In the event that the Company's assumptions and expectations change, it may have to revise its ROU assets and operating lease liabilities.

The following table represents the maturities of the operating lease liabilities as of September 30, 2021:

2022	$	166,744
2023		167,475
2024		175,520
2025		176,251
2026		184,296
Thereafter		168,939
Total lease payments	$	1,039,225
Less: Imputed interest		(117,599)
Total	$	921,626

3. REVENUES

Natural gas and oil derivative contracts

See Note 12 for discussion of the Company's accounting for derivative contracts.

Revenues from Contracts with Customers

Natural gas, oil and NGL sales

Sales of natural gas, oil and NGL are recognized when production is sold to a purchaser and control has transferred. Oil is priced on the delivery date based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. The price the Company receives for natural gas and NGL is tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality and heat content of natural gas, and prevailing supply and demand conditions, so that the price of natural gas fluctuates to remain competitive with other available natural gas supplies. These market indices are determined on a monthly basis. Each unit of commodity is considered a separate performance obligation; however, as consideration is variable, the Company utilizes the variable consideration allocation exception permitted under the standard to allocate the variable consideration to the specific units of commodity to which they relate.

Disaggregation of natural gas, oil and NGL revenues

The following table presents the disaggregation of the Company's natural gas, oil and NGL revenues for the year ended September 30, 2021.

	Year Ended September 30, 2021		
	Royalty Interest	Working Interest	Total
Natural gas revenue	$ 9,892,074	$ 11,074,934	$ 20,967,008
Oil revenue	6,787,084	5,913,801	12,700,885
NGL revenue	1,752,877	2,328,274	4,081,151
Natural gas, oil and NGL sales	$ 18,432,035	$ 19,317,009	$ 37,749,044

Performance obligations

The Company satisfies the performance obligations under its natural gas, oil and NGL sales contracts upon delivery of its production and related transfer of title to purchasers. Upon delivery of production, the Company has a right to receive consideration from its purchasers in amounts that correspond with the value of the production transferred.

Allocation of transaction price to remaining performance obligations

Natural gas, oil and NGL sales

As the Company has determined that each unit of product generally represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required. The Company has utilized the practical expedient in ASC 606, which permits the Company to allocate variable consideration to one or more but not all performance obligations in the contract if the terms of the variable payment relate specifically to the Company's efforts to satisfy that performance obligation and allocating the variable amount to the performance obligation is consistent with the allocation objective under ASC 606. Additionally, the Company will not disclose variable consideration subject to this practical expedient.

Prior-period performance obligations and contract balances

The Company records revenue in the month production is delivered to the purchaser. As a non-operator, the Company has limited visibility into the timing of when new wells start producing, and production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices for these properties are estimated and recorded within the natural gas, oil and NGL sales receivables line item on the Company's balance sheets. The difference between the Company's estimates and the actual amounts received for natural gas, oil and NGL sales is recorded in the quarter that payment is received from the third party. For the years ended September 30, 2021, 2020 and 2019, revenue recognized in these reporting periods related to performance obligations satisfied in prior reporting periods for existing wells was considered a change in estimate.

4. INCOME TAXES

The Company's provision (benefit) for income taxes is detailed as follows:

	2021	2020	2019
Current:			
Federal	$ 315,050	$ (3,642,000)	$ (1,388,000)
State	19,000	-	19,000
	334,050	(3,642,000)	(1,369,000)
Deferred:			
Federal	(824,000)	(3,611,000)	(9,763,000)
State	(161,101)	(1,036,000)	(2,349,000)
	(985,101)	(4,647,000)	(12,112,000)
	$ (651,051)	$ (8,289,000)	$ (13,481,000)

The difference between the provision (benefit) for income taxes and the amount which would result from the application of the federal statutory rate to income before provision (benefit) for income taxes is analyzed below for the years ended September 30:

	2021	2020	2019
Provision (benefit) for income taxes at statutory rate	$ (1,429,291)	$ (6,765,705)	$ (11,387,447)
Change in valuation allowance	1,228,899	96,000	-
Percentage depletion	(412,650)	(258,300)	(431,340)
State income taxes, net of federal provision (benefit)	(176,960)	(939,310)	(1,986,850)
Effect of NOL Carryback Rate	-	(610,803)	-
Restricted stock tax benefit	76,000	58,000	185,000
Deferred directors' compensation benefit	54,000	79,000	(38,000)
Law change	47,000	-	-
Other	(38,049)	52,118	177,637
	$ (651,051)	$ (8,289,000)	$ (13,481,000)

Deferred tax assets and liabilities, resulting from differences between the financial statement carrying amounts and the tax basis of assets and liabilities, consist of the following at September 30:

	2021	2020
Deferred tax liabilities:		
Financial basis in excess of tax basis, principally intangible drilling costs capitalized for financial purposes and expensed for tax purposes	$ 4,090,017	$ 3,880,307
Derivative contracts	-	-
Total deferred tax liabilities	4,090,017	3,880,307
Deferred tax assets:		
State net operating loss carry forwards	238,439	391,193
Federal net operating loss carry forwards	-	369,523
Statutory depletion carryover	286,440	346,414
Asset retirement obligations	483,990	499,708
Deferred directors' compensation	390,683	436,225
Restricted stock expense	303,674	220,301
Derivative contracts	3,278,067	176,963
Other	91,717	110,973
Total deferred tax assets	5,073,010	2,551,300
Deferred tax asset valuation allowance	1,251,096	-
State NOL valuation allowance	75,803	-
Net deferred tax (assets) liabilities	$ 343,906	$ 1,329,007

Included in state net operating loss carry forwards at September 30, 2021, the Company had a deferred tax asset of $127,656 related to Oklahoma state income tax net operating loss ("OK NOL") carry forwards, which begin to expire in 2037. The Company had a deferred tax asset of $84,326 related to Arkansas state income tax net operating loss ("AR NOL") carry forwards, which begin to expire in 2022. There is no valuation allowance for OK NOLs, as it is more likely than not that these will be utilized before expiration. The Company has a valuation allowance of $71,000 for the AR NOLs and $1,251,096 for state and federal deferred tax assets, as it is more likely than not that these will not be utilized before expiration.

The federal Coronavirus Aid, Relief, and Economic Security Act ("CARES Act") was enacted on March 27, 2020. The CARES Act provides relief to corporate taxpayers by permitting a five-year carryback of 2018-2020 Net Operating Losses ("NOLs"), removing the 80% limitation on the carryback of those NOLs, increasing the Section 163(j) 30% limitation on interest expense deductibility to 50% of adjusted taxable income for 2019 and 2020, and accelerates refunds for minimum tax credit carryforwards, along with a few other provisions. On July 28, 2020, final regulations were issued under Section 163(j) which modified the calculation under the previous proposed regulations of adjusted taxable income for purposes of the 50% limitation on interest expense. Under the final regulations, depreciation, amortization, and depletion capitalizable under Section 263A is now added back to tentative taxable income. This change allows all interest expense to be deductible for 2020 and reduces the associated deferred tax asset to zero. During the quarter ended March 31,2021, the Company received a tax refund associated with the AMT credits totaling $1.4 million, which was accelerated due to the CARES Act. Additionally, the Company has a $2.2 million receivable associated with the carryback of the 2020 federal net operating loss.

5. DEBT

On September 1, 2021, the Company entered into a $100,000,000 credit facility (the "Credit Facility") with a group of banks headed by Independent Bank, which replaced the Company's prior credit facility with BOKF, NA dba Bank of Oklahoma ("BOKF"), as administrative agent, which the Company repaid in full and terminated. The Credit Facility has a current borrowing base of $27,500,000 as of September 30, 2021, and a maturity date of September 1, 2025. The Credit Facility is secured by the Company's personal property and at least 80% of the total value of the proved, developed and producing oil and gas properties. The interest rate is based on either (a) LIBOR plus an applicable margin ranging from 2.750% to 3.750% per annum based on the Company's Borrowing Base Utilization or (b) the greater of (1) the Prime Rate in effect for such day, or (2) the overnight cost of federal funds as announced by the US Federal Reserve System in effect on such day plus one-half of one percent (0.50%), plus, in each case, an applicable margin ranging from 1.750% to 2.750% per annum based on the Company's Borrowing Base Utilization. The election of Independent Bank prime or LIBOR is at the Company's discretion. The interest rate spread from Independent Bank prime or LIBOR will be charged based on the ratio of the loan balance to the borrowing base. The interest rate spread from LIBOR or the prime rate increases as a larger percent of the borrowing base is advanced. At September 30, 2021, the effective interest rate was 3.75%.

The Company’s debt is recorded at the carrying amount on its balance sheets. The carrying amount of the Credit Facility approximates fair value because the interest rates are reflective of market rates. Debt issuance costs associated with the Credit Facility are presented in Other, net on the Company’s balance sheets. Total debt issuance cost net of amortization as of September 30, 2021, was $284,349. The debt issuance cost is amortized over the life of the Credit Facility.

Determinations of the borrowing base are made semi-annually (usually June and December) or whenever the banks, in their sole discretion, believe that there has been a material change in the value of the Company’s natural gas and oil properties. The Credit Facility contains customary covenants which, among other things, require periodic financial and reserve reporting and place certain limits on the Company’s incurrence of indebtedness, liens, make fundamental changes, and engage in certain transactions with affiliates. The Credit Agreement also restricts the Company’s ability to make certain restricted payments if before or after the Restricted Payment (i) the Available Commitment is less than ten percent (10%) of the Borrowing Base or (ii) the Leverage Ratio on a pro forma basis is greater than 2.50 to 1.00. In addition, the Company is required to maintain certain financial ratios, a current ratio (as described in the Credit Agreement) of no less than 1.0 to 1.0 and a funded debt to EBITDAX (as defined in the Credit Agreement) of no more than 3.5 to 1.0 based on the trailing twelve months. At September 30, 2021 and 2020, the Company was in compliance with the covenants of the Credit Facility, had $17,500,000 outstanding, and had $10,000,000 of borrowing base availability under the Credit Facility. All capitalized terms in this description of the Credit Facility that are not otherwise defined in this Annual Report shall have the meaning assigned to them in the Credit Agreement.

6. STOCKHOLDERS’ EQUITY

In May 2014, the Board adopted stock repurchase resolutions (the “Repurchase Program”) to allow management, at its discretion, to purchase the Company’s Common Stock as treasury shares up to an amount equal to the aggregate number of shares of Common Stock awarded pursuant to the 2010 Restricted Stock Plan (“2010 Stock Plan”), as amended, contributed by the Company to its ESOP and credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

Effective in May 2018, the Board approved an amendment to the Company’s existing stock Repurchase Program. As amended, the Repurchase Program continues to allow the Company to repurchase up to $1.5 million of the Company’s Common Stock at management’s discretion. The Board added language to clarify that this is intended to be an evergreen program as the repurchase of an additional $1.5 million of the Company’s Common Stock is authorized and approved whenever the previous amount is utilized. In addition, the number of shares allowed to be purchased by the Company under the Repurchase Program is no longer capped at an amount equal to the aggregate number of shares of Common Stock (i) awarded pursuant to the 2010 Stock Plan, as amended, (ii) contributed by the Company to its ESOP, and (iii) credited to the accounts of directors pursuant to the Deferred Compensation Plan for Non-Employee Directors.

On August 25, 2021, the Company entered into an At-The-Market Equity Offering Sales Agreement, pursuant to which the Company may offer and sell from time to time up to 3 million shares of Common Stock.

7. EARNINGS (LOSS) PER SHARE (“EPS”)

Basic and diluted earnings (loss) per common share is calculated using net income (loss) divided by the weighted average number of shares of Common Stock outstanding, including unissued, vested directors’ deferred compensation shares of 183,334, 154,142 and 168,586, respectively, during the 2021, 2020 and 2019 periods.

For the years ended September 30, 2021, 2020 and 2019, the Company did not include restricted stock in the diluted EPS calculation because the effect would have been antidilutive. The average shares outstanding of restricted stock excluded from the diluted EPS calculation was 141,690, 80,809 and 29,708 for the years ended September 30, 2021, 2020 and 2019, respectively.

The following table sets forth the computation of earnings (loss) per share.

	Year Ended September 30, 2021	2020	2019
Basic EPS			
Numerator:			
Basic net income (loss)	$ (6,217,237)	$ (23,952,037)	$ (40,744,938)
Denominator:			
Basic weighted average shares outstanding	25,925,536	17,010,934	16,743,746
Basic EPS	$ (0.24)	$ (1.41)	$ (2.43)
Diluted EPS			
Numerator:			
Basic net income (loss)	$ (6,217,237)	$ (23,952,037)	$ (40,744,938)
Diluted net income (loss)	(6,217,237)	(23,952,037)	(40,744,938)
Denominator:			
Basic weighted average shares outstanding	25,925,536	17,010,934	16,743,746
Effects of dilutive securities:			
Unvested restricted stock	-	-	-
Diluted weighted average shares outstanding	25,925,536	17,010,934	16,743,746
Diluted EPS	$ (0.24)	$ (1.41)	$ (2.43)

8. EMPLOYEE STOCK OWNERSHIP PLAN ("ESOP")

The Company's ESOP was established in 1984 and is a tax qualified, defined contribution plan. Company contributions were made at the discretion of the Board, and, to date, all contributions have been made in shares of Company Common Stock. For contributions of Common Stock, the Company recorded as expense the fair market value of the stock contributed. Effective January 1, 2021, the Company terminated the ESOP and established a new defined contribution 401K only plan. All ESOP participants were fully vested in all Company Common Stock held in their accounts, and those shares were transferred to their new 401K accounts. The Company began matching up to 5% of 401K contributions in cash starting January 1, 2021.

Contributions to the plan consisted of:

Year	Shares	Amount
2021	-	$ -
2020	72,101	$ 103,104
2019	26,629	$ 372,274

9. DEFERRED COMPENSATION PLAN FOR DIRECTORS

Annually, independent directors may elect to be included in the Company's Deferred Directors' Compensation Plan for Non-Employee Directors (the "Plan"). The Plan provides that each independent director may individually elect to be credited with future unissued shares of Company Common Stock rather than cash for all or a portion of the annual retainers, and may elect to receive shares, when issued, over annual time periods up to ten years. These unissued shares are recorded to each director's deferred compensation account at the closing market price of the shares at each quarter end. Only upon a director's retirement, termination, death or a change-in-control of the Company will the shares recorded for such director under the Plan be issued to the director. The promise to issue such shares in the future is an unsecured obligation of the Company. As of September 30, 2021, there were 232,091 shares (177,678 shares at September 30, 2020) recorded under the Plan. The deferred balance outstanding at September 30, 2021, under the Plan was $1,768,151 ($1,874,007 at September 30, 2020). Expenses totaling $234,466, $228,408 and $272,491 were charged to the Company's results of operations for the years ended September 30, 2021, 2020 and 2019, respectively, and are included in general and administrative expense in the accompanying Statements of Operations.

10. RESTRICTED STOCK PLAN AND LONG-TERM INCENTIVE PLAN

In March 2010, shareholders approved the Company's 2010 Stock Plan, which made available 200,000 shares of Common Stock to provide a long-term component to the Company's total compensation package for its officers and to further align the interest of its officers with those of its shareholders. In March 2014, shareholders approved an amendment to increase the number of shares of Common Stock reserved for issuance under the 2010 Stock Plan from 200,000 shares to 500,000 shares and to allow the grant of shares of restricted stock to our directors. In March 2020, shareholders approved an amendment to increase the number of shares of Common Stock reserved for issuance under the 2010 Stock Plan to 750,000 shares. The 2010 Stock Plan, as amended, is designed to provide as much flexibility as possible for future grants of restricted stock so the Company can respond as necessary to provide competitive compensation in order to retain, attract and motivate officers of the Company and to align their interests with those of the Company's shareholders.

In June 2010, the Company began awarding shares of the Company's Common Stock as restricted stock (time-based) to certain officers. The restricted stock vests at the end of the vesting period and contains nonforfeitable rights to receive dividends and voting rights during the vesting period. The fair value of the shares was based on the closing price of the shares on their award date and will be recognized as compensation expense ratably over the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury or the Company's authorized but unissued shares.

In December 2010, the Company also began awarding shares of the Company's Common Stock, subject to certain share price performance standards (market-based), as restricted stock to certain officers. Vesting of these shares is based on the performance of the market price of the Common Stock over the vesting period. The fair value of the performance shares was estimated on the grant date using a Monte Carlo valuation model that factors in information, including the expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance shares. Compensation expense for the performance shares is a fixed amount determined at the grant date and is recognized over the vesting period regardless of whether performance shares are awarded at the end of the vesting period. Should the awards vest, they are expected to be issued out of shares held in treasury or the Company's authorized but unissued shares.

In May 2014, the Company also began awarding shares of the Company's Common Stock as restricted stock (time-based) to its non-employee directors. The restricted stock vests annually. The fair value of the shares is based on the closing price of the shares on their award date and will be recognized as compensation expense ratably over the vesting period. Upon vesting, shares are expected to be issued out of shares held in treasury or the Company's authorized but unissued shares.

In March of 2021, shareholders approved the PHX Minerals Inc. 2021 Long-Term Incentive Plan (the "LTIP"). The terms and conditions of awards granted under the Company's 2010 Stock Plan prior to the LTIP are not affected by the adoption of the LTIP. The LTIP expressly prohibits the payment of dividends or dividend equivalents on any award before the date on which the award vests. Awards under the LTIP will be subject to any clawback or recapture policy that the Company may adopt from time to time or any clawback or recapture provisions set forth in an award agreement.

On January 5, 2021, the Company awarded 303,750 market-based shares of the Company's Common Stock as restricted stock to certain officers. The restricted stock vests at the end of a three-year period and contains non-forfeitable rights to receive dividends and voting rights during the vesting period. The market-based shares that do not meet certain market performance criteria at a certain date are forfeited. The market-based shares had a fair value on their award date of $826,457. The fair value of the market-based awards will be recognized as compensation expense ratably over the vesting period. The fair value of the market-based shares on their award date is calculated by simulating the Company's stock prices as compared to the S&P Oil & Gas Exploration & Production ETF (XOP) prices utilizing a Monte Carlo model covering the market performance period (December 18, 2020, through December 18, 2023).

On March 22, 2021, the Company awarded 125,000 time-based shares of the Company's Common Stock as restricted stock to its non-employee directors. The shares issued as restricted stock contain voting rights during the vesting period but do not include the right to dividends prior to the stock vesting. The restricted stock vests on December 31, 2021. These time-based shares had a fair value on their award date of $396,252.

Compensation expense for the restricted stock awards is recognized in G&A. Forfeitures of awards are recognized when they occur.

The following table summarizes the Company's pre-tax compensation expense for the years ended September 30, 2021, 2020 and 2019, related to the Company's market-based, time-based and performance-based restricted stock:

	Year Ended September 30,		
	2021	2020	2019
Market-based, restricted stock	$ 247,601	$ 295,397	$ 367,091
Time-based, restricted stock	$ 553,599	$ 448,500	404,706
Performance-based, restricted stock	-	-	-
Total compensation expense	$ 801,200	$ 743,897	$ 771,797

A summary of the Company's unrecognized compensation cost for its unvested market-based, time-based and performance-based restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table:

	Unrecognized Compensation Cost	Weighted Average Period (in years)
Market-based, restricted stock	$ 646,509	2.20
Time-based, restricted stock	372,963	0.88
Performance-based, restricted stock	-	
Total	$ 1,019,472	

Upon vesting, shares are expected to be issued out of shares held in treasury and authorized but unissued shares.

A summary of the status of, and changes in, unvested shares of restricted stock awards is presented below:

	Market-Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value	Time-Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value	Performance-Based Unvested Restricted Awards	Weighted Average Grant-Date Fair Value
Unvested shares as of September 30, 2018	92,704	$ 11.00	28,667	$ 20.40	-	$ -
Granted	43,287	8.24	27,978	15.61	-	-
Vested	-	-	(24,785)	18.30	-	-
Forfeited	(89,321)	10.08	(13,153)	18.23	-	-
Unvested shares as of September 30, 2019	46,670	$ 10.21	18,707	$ 17.54	-	$ -
Granted	39,579	8.83	102,154	9.21	39,579	-
Vested	-	-	(20,410)	13.35	-	-
Forfeited	(24,779)	11.34	(9,929)	13.93	(4,765)	-
Unvested shares as of September 30, 2020	61,470	$ 8.87	90,522	$ 9.49	34,814	$ -
Granted	303,750	2.72	125,000	3.17	-	-
Vested	-	-	(9,860)	14.08	-	-
Forfeited	(9,071)	11.34	(2,562)	13.00	-	-
Unvested shares as of September 30, 2021	356,149	3.56	203,100	5.33	34,814	-

The intrinsic value of the vested shares in 2021 was $56,589.

11. PROPERTIES AND EQUIPMENT

Impairment

During the quarter ended June 30, 2021, the Company recorded impairment of $37,879 on producing properties and $7,976 on wells that the Company wrote off.

During the quarter ended March 31, 2020, impairment of $19.3 million and $7.3 million was recorded on our Fayetteville Shale and Eagle Ford fields, respectively. The remaining $2.7 million of impairment was taken on other producing assets. The discounted cash flows of the properties were prepared using NYMEX strip pricing as of March 31, 2020, using a discount rate of 10% for proved developed and assigning no value to undeveloped locations. The Fayetteville Shale assets are dry-gas assets of which the Company acquired a portion in 2011. Low natural gas prices at March 31, 2020, were the primary reason for impairment in this field. The Company recognized an impairment related to the Eagle Ford at September 30, 2019, discussed below. The further impairment of the Eagle Ford assets at March 31, 2020, was due to the decline in commodity prices over fiscal year 2020.

For fiscal year 2019, impairment of $76.6 million was recorded on our Eagle Ford assets. The remaining $0.3 million of impairment was taken on other assets. The impairment on the Eagle Ford assets was caused by the Company making the strategic decision to cease participating with a working interest on its mineral and leasehold acreage going forward and therefore removing all working interest PUDs from the Company's reserve reports. The removal of the PUDs caused the Eagle Ford assets to fail the step one test for impairment, as its undiscounted cash flows were not high enough to cover the book basis of the assets. These assets were written down to their fair market value as required by GAAP. The Company determined the fair value based on discounted cash flows of the properties as well as active market bids received from interested potential buyers. The discounted cash flows of the properties were prepared using NYMEX strip pricing as of year-end, using a discount rate of 10% for proved developed and assigning no value to undeveloped locations. Market bids received from interested potential buyers corroborated the fair value of the discounted cash flows as of year-end. The fair value was determined to be $9.1 million based on the discounted cash flows and market quotes. The Company decided not to sell the assets after the marketing process was complete, as we believed that the market conditions were not ideal for selling at that time and that the highest and best use of the assets was to continue to own and produce out the Eagle Ford properties.

A further reduction in natural gas, oil and NGL prices or a decline in reserve volumes may lead to additional impairment in future periods that may be material to the Company.

Divestitures

Quarter Ended	Net mineral acres	Sale Price	Gain/(Loss)	Location
September 30, 2021				
	No significant divestitures			
June 30, 2021				
	2,857	$0.3 million	$0.2 million	Central Basin Platform, TX
March 31, 2021				
	No significant divestitures			
December 31, 2020				
	No significant divestitures			
September 30, 2020				
	5,925	$0.8 million	$0.7 million	Northwest OK
June 30, 2020				
	No significant divestitures			
March 31, 2020				
	No significant divestitures			
December 31, 2019				
	530	$3.4 million	$3.3 million	Eddy County, NM

Acquisitions

Quarter Ended	Net royalty acres (1)(2)	Purchase Price (1)	Area of Interest
September 30, 2021			
	817	$7.3 million	Haynesville / LA, TX
June 30, 2021			
	262	$1.3 million	Haynesville / LA
	131	$1.0 million	Haynesville / TX
	2,514	$13.0 million	SCOOP / OK
March 31, 2021			
	No significant acquisitions		
December 31, 2020			
	142	$1.0 million	Haynesville / TX
	184	$0.8 million	Haynesville / TX
	386	$3.5 million	Haynesville / TX
	297	$2.3 million	SCOOP / OK
September 30, 2020			
	No significant acquisitions		
June 30, 2020			
	No significant acquisitions		
March 31, 2020			
	No significant acquisitions		
December 31, 2019			
	964	$9.3 million	SCOOP / OK

(1) Excludes subsequent closing adjustments and insignificant acquisitions.
(2) An estimated net royalty equivalent was used for the minerals included in the net royalty acres.

All purchases made in 2020 and 2021 were of mineral and royalty acreage and were accounted for as asset acquisitions.

Asset Retirement Obligations

The following table shows the activity for the years ended September 30, 2021 and 2020, relating to the Company's asset retirement obligations:

	2021	2020
Asset retirement obligations as of beginning of the year	$ 2,897,522	$ 2,835,781
Wells acquired or drilled	-	4
Wells sold or plugged	(189,459)	(68,668)
Accretion of discount	128,109	130,405
Asset retirement obligations as of end of the year	$ 2,836,172	$ 2,897,522

As a non-operator, the Company does not control the plugging of wells in which it has a working interest and is not involved in the negotiation of the terms of the plugging contracts. This estimate relies on information gathered from outside sources as well as relevant information received directly from operators.

12. DERIVATIVES

The Company has entered into fixed swap contracts and costless collar contracts. These instruments are intended to reduce the Company's exposure to short-term fluctuations in the price of natural gas and oil. Collar contracts set a fixed floor price and a fixed ceiling price and provide payments to the Company if the index price falls below the floor or require payments by the Company if the index price rises above the ceiling. Fixed swap contracts set a fixed price and provide payments to the Company if the index price is below the fixed price or require payments by the Company if the index price is above the fixed price. These contracts cover only a portion of the Company's natural gas and oil production, provide only partial price protection against declines in natural gas and oil prices and may limit the benefit of future increases in prices.

On September 2, 2021, the Company settled all of its derivative contracts consisting of both swaps and costless collars with BOKF by paying $8.8 million. On September 3, 2021, the Company entered into new derivative contracts with BP Energy Company

("BP") that had similar terms to the contracts settled with BOKF and received a payment of $8.8 million from BP. The new derivative contracts consist of all fixed swap contracts and are secured under the Company's Credit Facility with Independent Bank. Management concluded that the financing element of the new derivative contracts with BP was other than insignificant due to the off-market terms of the fixed swap price. Due to the financing element, the Company is required to report all cash flows associated with these derivative contracts as "cash flows from financing activities" in the statement of cash flows. This requirement relates to all cash flows from the derivative and not just the portion of the cash flows relating to the financing element of the derivative. The derivative instruments have settled or will settle based on the terms below.

Derivative contracts in place as of September 30, 2021

Fiscal period	Contract total volume	Index	Contract average price
Natural gas fixed price swaps			
2022	3,869,000 Mmbtu	NYMEX Henry Hub	$2.91
2023	1,100,000 Mmbtu	NYMEX Henry Hub	$3.07
Oil fixed price swaps			
2022	138,000 Bbls	NYMEX WTI	$44.25
2023	30,000 Bbls	NYMEX WTI	$46.23

The Company's fair value of derivative contracts was a net liability of $13,784,467 as of September 30, 2021, and a net liability of $707,647 as of September 30, 2020. Realized and unrealized gains and (losses) are recorded in gains (losses) on derivative contracts on the Company's Statement of Operations. Cash receipts in the following table reflect the gain or loss on derivative contracts which settled during the respective periods, and the non-cash gain or loss reflect the change in fair value of derivative contracts as of the end of the respective periods. The $8.8 million in cash received from BP is a cash flow from a financing activity and is excluded from the table below.

	For the Year Ended September 30,		
	2021	2020	2019
Cash received (paid) on settled derivative contracts:			
Natural gas costless collars	$ (4,271,467)	$ 28,510	$ (191,200)
Natural gas fixed price swaps	(1,862,801)	1,687,600	817,160
Oil costless collars	(2,047,098)	1,011,472	(169,256)
Oil fixed price swaps	(3,744,303)	1,381,628	(259,719)
Cash received (paid) on settled derivative contracts, net	$ (11,925,669)	$ 4,109,210	$ 196,985
Non-cash gain (loss) on derivative contracts:			
Natural gas costless collars	$ 706,015	$ (706,015)	$ 10,453
Natural gas fixed price swaps	(3,624,108)	(1,535,122)	1,350,909
Oil costless collars	(63,169)	(538,022)	1,687,685
Oil fixed price swaps	(1,295,558)	(422,632)	2,859,113
Non-cash gain (loss) on derivative contracts, net	$ (4,276,820)	$ (3,201,791)	$ 5,908,160
Gains (losses) on derivative contracts, net	$ (16,202,489)	$ 907,419	$ 6,105,145

The fair value amounts recognized for the Company's derivative contracts executed with the same counterparty under a master netting arrangement may be offset. The Company has the choice to offset or not, but that choice must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on, or termination of, any one contract. Offsetting the fair values recognized for the derivative contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the balance sheets. The following table summarizes and reconciles the Company's derivative contracts' fair values at a gross level back to net fair value presentation on the Company's balance sheets at September 30, 2021, and September 30, 2020. The Company has offset all amounts subject to master netting agreements in the Company's balance sheets at September 30, 2021, and September 30, 2020.

	9/30/2021 Fair Value Commodity Contracts			9/30/2020 Fair Value Commodity Contracts		
	Current Assets	Current Liabilities	Non-Current Liabilities	Current Assets	Current Liabilities	Non-Current Liabilities
Gross amounts recognized	$ 17,395	$ 12,105,383	$ 1,696,479	$ 864,466	$ 1,146,408	$ 425,705
Offsetting adjustments	(17,395)	(17,395)	-	(864,466)	(864,466)	-
Net presentation on Balance Sheets	$ -	$ 12,087,988	$ 1,696,479	$ -	$ 281,942	$ 425,705

The fair value of derivative assets and derivative liabilities is adjusted for credit risk. The impact of credit risk was immaterial for all periods presented.

13. FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels.

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers 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 the Company values 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. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity fixed-price swaps and commodity options (i.e. price collars).

The Company uses an option pricing valuation model for option derivative contracts that considers various inputs including: future prices, time value, volatility factors, counterparty credit risk and current market and contractual prices for the underlying instruments. The values calculated are then compared to the values given by counterparties for reasonableness.

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

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis.

	Fair Value Measurement at September 30, 2021			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative Contracts - Swaps	$ -	$ (13,784,467)	$ -	$ (13,784,467)

	Fair Value Measurement at September 30, 2020			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative Contracts - Swaps	$ -	$ (64,801)	$ -	$ (64,801)
Derivative Contracts - Collars	$ -	$ (642,846)	$ -	$ (642,846)

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Year Ended September 30,					
	2021		2020		2019	
	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Producing Properties [a]	$ 587	$ 37,879	$ 5,288,710	$ 29,315,807	$ 9,101,032	$ 76,824,337

[a] At the end of each quarter, the Company assessed the carrying value of its producing properties for impairment. This assessment utilized estimates of future cash flows or fair value (selling price) less cost to sell if the property is held for sale. Significant judgments and assumptions in these assessments include estimates of future natural gas, oil and NGL prices using a forward NYMEX curve adjusted for projected inflation, locational basis differentials, drilling plans, expected capital costs and an applicable discount rate commensurate with risk of the underlying cash flow estimates. These assessments identified certain properties with carrying value in excess of their calculated fair values. This table excludes impairments on properties that were written off in the amount of $12,596 and $588,721 for the years ended September 30, 2021 and 2020, respectively.

At September 30, 2021, and September 30, 2020, the carrying values of cash and cash equivalents, receivables, and payables are considered to be representative of their respective fair values due to the short-term maturities of those instruments. Financial instruments include debt, which the valuation is classified as Level 2 as the carrying amount of the Company's revolving credit facility approximates fair value because the interest rates are reflective of market rates. The estimated current market interest rates are based primarily on interest rates currently being offered on borrowings of similar amounts and terms. In addition, no valuation input adjustments were considered necessary relating to nonperformance risk for the debt agreements.

14. INFORMATION ON NATURAL GAS AND OIL PRODUCING ACTIVITIES

The natural gas and oil producing activities of the Company are conducted within the contiguous United States (principally in Oklahoma, Texas, Louisiana, Arkansas and North Dakota) and represent substantially all of the business activities of the Company.

The following table shows sales to major purchasers, by percentage, through various operators/purchasers during 2021, 2020 and 2019.

	2021	2020	2019
Company A	14%	23%	23%
Company B	7%	6%	8%
Company C	0%	5%	8%

The loss of any of these major purchasers of natural gas, oil and NGL production could have a material adverse effect on the ability of the Company to produce and sell its natural gas, oil and NGL production.

15. SUBSEQUENT EVENTS

Acquisition

As previously disclosed in a Current Report on Form 8-K filed with the SEC on November 12, 2021, on November 10, 2021, the Company entered into a Purchase and Sale Agreement (the "Vendera Purchase Agreement") with Vendera Resources III, LP and Vendera Management III LLC to acquire certain mineral and royalty assets located in Bienville, Bossier, Caddo, DeSoto, Red River and Sabine Parishes, Louisiana, and Nacogdoches County, Texas, located in the Haynesville play (the "Vendera Assets"). As disclosed in a Current Report on Form 8-K filed with the SEC on December 1, 2021, on December 1, 2021, the Company completed the acquisition of the Vendera Assets for an aggregate consideration of $5,306,389, comprised of $626,389 in cash and 1,519,481 shares of the Company's Common Stock (the "Vendera Equity Consideration"). The Vendera Assets acquired include mineral and royalty assets totaling approximately 827 net royalty acres in the Haynesville play. The Vendera Purchase Agreement includes registration rights relating to the Vendera Equity Consideration pursuant to which the Company agrees to register with the SEC the shares constituting the Vendera Equity Consideration. The Company agrees to file a resale registration statement and to use commercially reasonable efforts to cause such registration statement to be declared effective as soon as reasonably practicable after the filing thereof. The Vendera Equity Consideration is subject to a 120-day lock-up period. The foregoing description of the Vendera Purchase Agreement is qualified in its entirety by reference to the full text of the Vendera Purchase Agreement, which was filed as Exhibit 10.1 to the Current Report on Form 8-K filed with the SEC on November 12, 2021.

Entry into Purchase and Sale Agreements

As previously disclosed in a Current Report on Form 8-K filed with the SEC on December 9, 2021, on December 6, 2021, the Company entered into two separate Purchase and Sale Agreements (collectively, the "Caddo Parish Purchase Agreements") with two sellers (the "Sellers") to acquire certain mineral interests, royalty interests and overriding royalty interests in the oil, gas and other minerals underlying certain lands located in Caddo Parish, Louisiana (the "Assets"). The Company entered into one purchase agreement with Merrimac Properties Partners, LLC and Quarter Horse Energy Partners, LLC (the "Merrimac Purchase Agreement") to acquire a portion of the Assets for consideration equal to $5,185,475 in cash, and a separate purchase agreement with Palmetto Investment Partners II, LLC (the "Palmetto Purchase Agreement") to acquire the remainder of the Assets for consideration equal to $601,797 in cash. The Assets include mineral and royalty interests totaling approximately 426 net royalty acres in the Haynesville play. The obligations of the Company and the Sellers to close each acquisition is subject to certain customary closing conditions as set forth in the Caddo Parish Purchase Agreements. There can be no assurance that the conditions to closing the acquisitions of the Assets will be satisfied. The above description of the Caddo Parish Purchase Agreements does not purport to be complete and is qualified in its entirety by reference to the full text of the Merrimac Purchase Agreement, which is filed as Exhibit 10.1 to the Current Report on Form 8-K filed with the SEC on December 9, 2021, and the Palmetto Purchase Agreement, which is filed as Exhibit 10.2 to the Current Report on Form 8-K filed with the SEC on December 9, 2021.

Divestitures

Subsequent to September 30, 2021, the Company divested approximately 708 working interest wellbores for net proceeds of approximately $4,625,000 in three separate transactions.

Borrowing Base Redetermination

As previously disclosed in a Current Report on Form 8-K filed with the SEC on December 9, 2021, on December 6, 2021, the Company entered into the First Amendment (the "Amendment") to the Credit Agreement. The Amendment provides for an increase to the Company's Borrowing Base from $27.5 million to $32.0 million. The Borrowing Base will remain at $32.0 million until the next scheduled semi-annual redetermination, which is scheduled to occur on or about June 1, 2022, unless otherwise redetermined pursuant to an Unscheduled Redetermination. In addition, the Amendment changes the commitment schedule to reallocate the Committed Sum and Commitment Percentage of each Lender under the Credit Agreement. All capitalized terms in this description of the Amendment that are not otherwise defined in this Form 10-K have the meaning assigned to them in the Credit Agreement. The above description of the Amendment does not purport to be complete and is qualified in its entirety by reference to the full text of the Amendment, which is filed as Exhibit 10.3 to the Current Report on Form 8-K filed with the SEC on December 9, 2021.

Federal Tax Refund

Subsequent to September 30, 2021, the Company received a $2.2 million federal tax refund included in the refundable income taxes line item on the Company's balance sheets as of September 30, 2021.

16. SUPPLEMENTARY INFORMATION ON NATURAL GAS, OIL AND NGL RESERVES (UNAUDITED)

Aggregate Capitalized Costs

The aggregate amount of capitalized costs of natural gas and oil properties and related accumulated depreciation, depletion and amortization as of September 30 is as follows:

	2021	2020
Producing properties	$ 319,984,874	$ 324,886,491
Non-producing minerals	38,328,699	18,808,689
Non-producing leasehold	2,137,399	185,125
	360,450,972	343,880,305
Accumulated depreciation, depletion and amortization	(257,250,452)	(263,277,422)
Net capitalized costs	$ 103,200,520	$ 80,602,883

Costs Incurred

For the years ended September 30, the Company incurred the following costs in natural gas and oil producing activities:

	2021	2020	2019
Property acquisition costs	$ 30,963,579	$ 10,453,119	$ 6,235,905
Development costs	518,058	273,825	3,012,095
	$ 31,481,637	$ 10,726,944	$ 9,248,000

Estimated Quantities of Proved Natural Gas, Oil and NGL Reserves

The following unaudited information regarding the Company's natural gas, oil and NGL reserves is presented pursuant to the disclosure requirements promulgated by the SEC and the FASB.

Proved natural gas and oil reserves are those quantities of natural gas and oil 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. 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. 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. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural 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. 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: (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of DeGolyer and MacNaughton of Dallas, Texas, prepared the Company’s natural gas, oil and NGL reserves estimates as of September 30, 2021, 2020 and 2019.

The Company’s net proved natural gas, oil and NGL reserves, which are located in the contiguous United States, as of September 30, 2021, 2020 and 2019, have been estimated by the Company’s Independent Consulting Petroleum Engineering Firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007).” The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

All of the reserve estimates are reviewed and approved by our Director of Engineering, Danielle Mezo. Ms. Mezo holds a Bachelor of Science degree in Petroleum Engineering from the University of Oklahoma and a Professional Engineering License in Petroleum Engineering in the State of Oklahoma. Ms. Mezo has more than 10 years of experience in the oil and gas industry. Before joining the Company, Ms. Mezo held various reservoir engineering, reserves, acquisitions, corporate planning, and management positions at SandRidge Energy.

The Director of Engineering, and internal staff work closely with the Independent Consulting Petroleum Engineers to ensure the integrity, accuracy and timeliness of data furnished to them for their reserves estimation process. The Company provides historical information (such as ownership interest, gas and oil production, well test data, commodity prices, operating costs, handling fees and development costs) for all properties to the Independent Consulting Petroleum Engineers. Throughout the year, the Director of Engineering and internal staff meet regularly with representatives of the Independent Consulting Petroleum Engineers to review properties and discuss methods and assumptions.

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers (SPE) entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019” and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history. Based on the current stage of field development, production performance, development plans and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves were estimated for locations that have been permitted, are currently drilling, are drilled but not yet completed, or locations where the operator has indicated to the Company its intention to drill.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas). Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs. In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Accordingly, these estimates should be expected to change, and such changes could be material and occur in the near term as future information becomes available.

Net quantities of proved, developed and undeveloped natural gas, oil and NGL reserves are summarized as follows:

	Proved Reserves			
	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Total Bcfe
September 30, 2018	120,062,036	5,984,422	2,934,190	173.6
Revisions of previous estimates	(35,644,135)	(3,266,351)	(890,046)	(60.6)
Acquisitions (divestitures)	(948,496)	(322,023)	(18,881)	(3.0)
Extensions, discoveries and other additions	3,891,262	313,241	164,276	6.8
Production	(7,086,761)	(329,199)	(216,259)	(10.4)
September 30, 2019	80,273,906	2,380,090	1,973,280	106.4
Revisions of previous estimates	(34,666,426)	(1,094,923)	(774,214)	(45.9)
Acquisitions (divestitures)	911,853	57,721	70,933	1.7
Extensions, discoveries and other additions	1,816,144	260,555	118,480	4.1
Production	(5,962,704)	(269,786)	(168,622)	(8.6)
September 30, 2020	42,372,773	1,333,657	1,219,857	57.7
Revisions of previous estimates	21,930,522	287,961	389,825	26.0
Acquisitions (divestitures)	6,994,423	79,576	36,911	7.7
Extensions, discoveries and other additions	354,670	28,125	26,748	0.7
Production	(6,699,720)	(224,479)	(171,488)	(9.1)
September 30, 2021	64,952,668	1,504,840	1,501,853	83.0

The prices used to calculate reserves and future cash flows from reserves for natural gas, oil and NGL, respectively, were as follows: September 30, 2021 - \$2.79/Mcf, \$56.51/Bbl, \$20.58/Bbl; September 30, 2020 - \$1.62/Mcf, \$40.18/Bbl, \$9.95/Bbl; September 30, 2019 - \$2.48/Mcf, \$54.40/Bbl, \$19.30/Bbl.

The revisions of previous estimates from 2020 to 2021 were primarily the result of:

- Positive pricing revisions of 28.1 Bcfe comprised of (i) proved developed revisions of 28.7 Bcfe due to natural gas and oil wells extending their economic limits later than was projected in 2020 due to higher gas and oil prices and other reserve parameters, such as differentials and lease operating costs, partially offset by (ii) proved undeveloped negative revisions of 0.6 Bcfe resulting from permits that expired and were not renewed by the operator, as locations are only considered PUD if they are permitted, in progress, or drilled and uncompleted (DUC).

- Negative performance revisions of 2.1 Bcfe (comprised of all proved developed), principally due to lower performance of high-interest Mississippian and Woodford wells in the STACK play in Oklahoma that were brought online in 2021, and therefore converted from proved undeveloped to proved producing reserves year over year, and, to a lesser extent, lower performance in the Fayetteville Shale gas properties in Arkansas and Anadarko Basin Granite Wash gas properties in Western Oklahoma.

Acquisitions and divestitures were the result of:

- The acquisition of 8.6 Bcfe, predominately in the active drilling programs of the Haynesville Shale play in east Texas and western Louisiana and the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma, of which 4.0 Bcfe were proved developed and 4.6 Bcfe were proved undeveloped.

- The sale of 0.9 Bcfe proved developed, consisting of predominately working interest in low rate, legacy vertical wells in Oklahoma.

Extensions, discoveries and other additions from 2020 to 2021 are principally attributable to:

- Reserve extensions, discoveries and other additions of 0.7 Bcfe (comprised of 0.4 Bcfe proved developed and 0.3 Bcfe proved undeveloped reserves) principally resulting from:

  a) The Company’s royalty interest ownership in the ongoing development of unconventional natural gas, oil and NGL utilizing horizontal drilling in the Mississippi and Woodford Shale intervals in the SCOOP and STACK plays in the Ardmore and Anadarko basins of Oklahoma.

  b) The Company’s royalty interest ownership in ongoing development of unconventional natural gas, oil and NGL utilizing horizontal drilling in the Anadarko Granite Wash play, which is part of the deep Anadarko Basin in Oklahoma and Texas.

Production of 9.1 Bcfe from the Company’s natural gas and oil properties.

	Proved Developed Reserves			Proved Undeveloped Reserves		
	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Oil (Barrels)	NGL (Barrels)
September 30, 2019	67,713,193	1,863,096	1,747,242	12,560,713	516,994	226,038
September 30, 2020	40,924,083	1,148,989	1,135,864	1,448,690	184,668	83,993
September 30, 2021	60,287,881	1,439,860	1,467,092	4,664,787	64,980	34,761

The following details the changes in proved undeveloped reserves for 2021 (Mcfe):

Beginning proved undeveloped reserves	3,060,656
Proved undeveloped reserves transferred to proved developed	(2,060,368)
Revisions	(629,317)
Extensions and discoveries	246,993
Sales	-
Purchases	4,645,269
Ending proved undeveloped reserves	5,263,233

During fiscal year 2021, total net PUD reserves increased by 2.2 Bcfe. In fiscal year 2021, a total of 2.1 Bcfe (67% of the beginning balance) was transferred to proved developed. The remaining balance of approximately 4.3 Bcfe (140% of the beginning balance) of positive revisions to PUD reserves consist of acquisitions of 4.6 Bcfe in the Haynesville Shale in Texas and Louisiana and Meramec and Woodford SCOOP play in Oklahoma, and additions and extensions of 0.2 Bcfe within the active drilling program areas of (i) STACK Meramec and Woodford in western Oklahoma, (ii) the SCOOP Woodford Shale in western Oklahoma and (iii) Bakken in North Dakota. These were slightly offset by negative revisions of 0.6 Bcfe resulting from permits that expired and were not renewed by the operator, as locations are only considered PUD if they are permitted, in progress, or drilled and uncompleted (DUC).

The Company anticipates that all current PUD locations will be drilled and converted to PDP within five years of the date they were added. However, PUD locations and associated reserves, which are no longer projected to be drilled within five years from the date they were added to PUD reserves, will be removed as revisions at the time that determination is made. In the event that there are undrilled PUD locations at the end of the five-year period, the Company intends to remove the reserves associated with those locations from proved reserves as revisions.

Standardized Measure of Discounted Future Net Cash Flows

Accounting Standards prescribe guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs to the estimated quantities of natural gas, oil and NGL to be produced. Actual future prices and costs may be materially higher or lower than the unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced, based on continuation of the economic conditions applied for such year.

Estimated future income taxes are computed using current statutory income tax rates, including consideration for the current tax basis of the properties and related carry forwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect the Company's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates affect the valuation process.

	2021	2020	2019
Future cash inflows	$ 297,138,886	$ 134,179,216	$ 366,697,321
Future production costs	(115,681,617)	(66,136,222)	(153,935,373)
Future development and asset retirement costs	(1,873,126)	(1,957,225)	(1,917,937)
Future income tax expense	(40,697,140)	(13,224,535)	(47,788,416)
Future net cash flows	138,887,003	52,861,234	163,055,595
10% annual discount	(64,096,661)	(21,727,081)	(77,494,066)
Standardized measure of discounted future net cash flows	$ 74,790,342	$ 31,134,153	$ 85,561,529

Changes in the standardized measure of discounted future net cash flows are as follows:

	2021	2020	2019
Beginning of year	$ 31,134,153	$ 85,561,529	$ 156,325,854
Changes resulting from:			
Sales of natural gas, oil and NGL, net of production costs	(25,812,485)	(12,692,681)	(25,072,122)
Net change in sales prices and production costs	43,951,090	(46,499,344)	(76,588,460)
Net change in future development and asset retirement costs	49,542	(20,571)	43,607,535
Extensions and discoveries	803,714	2,841,807	7,074,245
Revisions of quantity estimates	33,482,964	(28,332,653)	(60,308,497)
Acquisitions (divestitures) of reserves-in-place	9,041,028	1,169,819	(3,134,783)
Accretion of discount	3,893,028	11,039,792	20,457,930
Net change in income taxes	(13,937,867)	17,037,980	23,413,194
Change in timing and other, net	(7,814,825)	1,028,475	(213,367)
Net change	43,656,189	(54,427,376)	(70,764,325)
End of year	$ 74,790,342	$ 31,134,153	$ 85,561,529

17. QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

The following is a summary of the Company's unaudited quarterly results of operations.

	Fiscal 2021 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 6,172,376	$ 6,056,236	$ 5,671,489	$ 4,071,567
Income (loss) before provision for income taxes	$ (665,720)	$ (716,723)	$ (2,172,594)	$ (3,313,251)
Net income (loss)	$ (596,720)	$ (499,723)	$ (1,356,594)	$ (3,764,200)
Earnings (loss) per share	$ (0.03)	$ (0.02)	$ (0.05)	$ (0.14)

	Fiscal 2020 Quarter Ended			
	December 31	March 31	June 30	September 30
Revenues	$ 7,303,643	$ 11,311,287	$ 2,702,275	$ 3,651,178
Income (loss) before provision for income taxes	$ 2,146,114	$ (27,441,814)	$ (4,433,155)	$ (2,512,182)
Net income (loss)	$ 1,892,114	$ (20,454,814)	$ (3,555,215)	$ (1,834,122)
Earnings (loss) per share	$ 0.11	$ (1.24)	$ (0.21)	$ (0.07)

ITEM 9 CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A CONTROLS AND PROCEDURES

(a) EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Company maintains “disclosure controls and procedures,” as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including the Company’s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, management recognizes that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Based on their evaluation, the Company’s Chief Executive Officer and Chief Financial Officer have concluded that the Company’s disclosure controls and procedures were not effective as of September 30, 2021 as a result of the material weakness described below.

(b) MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company’s management is responsible for establishing and maintaining adequate “internal control over financial reporting,” as such term is defined in Exchange Act Rule 13a-15(f). The Company’s internal control structure is designed to provide reasonable assurance to its management and Board regarding the reliability of financial reporting and the preparation and fair presentation of its financial statements prepared for external purposes in accordance with U.S. generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting can provide only reasonable assurance that the objectives of the control system are met and may not prevent or detect misstatements. In addition, any evaluation of the effectiveness of internal controls over financial reporting in future periods is subject to risk that those internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company’s management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the Company’s internal control over financial reporting based on the *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management identified a material weakness in the Company’s internal control over financial reporting, which is described below.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis.

During the audit process related to the fiscal year ended September 30, 2021, management, together with the Company’s independent registered public accounting firm, identified a material weakness in one of the Company’s internal controls related to the review of the annual income tax provision prepared by a third-party firm. Specifically, the Company’s review of the annual income tax provision did not include a process to sufficiently evaluate deferred tax assets to determine if a valuation allowance was necessary. Additionally, the review was not sufficiently detailed to identify a material misstatement in deferred income taxes.

Based on the results of its evaluation and the material weakness described above, the Company’s management concluded that the Company’s internal control over financial reporting was not effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with GAAP as of September 30, 2021.

The Company’s independent registered public accounting firm, Ernst & Young LLP, has issued an attestation report regarding its assessment of the Company’s internal control over financial reporting as of September 30, 2021, presented preceding the Company’s financial statements included in this Form 10-K. Additionally, the financial statements for the years ended September 30, 2020 and 2019, covered in this Annual Report on Form 10-K, have also been audited by the Company’s independent registered public accounting firm, whose report is presented preceding their report on the Company’s internal control over financial reporting.

(c) CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in the Company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting made during the fiscal quarter ended September 30, 2021, or subsequent to the date the assessment was completed through the filing of this Form 10-K. The Company's management has commenced the process of designing a remediation plan to remediate the material weakness described above, although such remediation plan has not yet been designed or implemented.

ITEM 9B OTHER INFORMATION

None

ITEM 9C DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

The information called for by Part III of Form 10-K (Item 10 – Directors and Executive Officers and Corporate Governance, Item 11 – Executive Compensation, Item 12 – Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters, Item 13 – Certain Relationships and Related Transactions, and Director Independence and Item 14 – Principal Accountant Fees and Services), is incorporated by reference from the Company's definitive proxy statement, which will be filed with the SEC within 120 days after the end of the fiscal year to which this Annual Report relates.

PART IV

ITEM 15 EXHIBITS, FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENT SCHEDULES

The Company has omitted all schedules because the conditions requiring their filing do not exist or because the required information appears in the Company's Financial Statements, including the notes to those statements.

EXHIBITS

(1.1)	Underwriting Agreement, dated April 16, 2021, between PHX Minerals Inc. and Stifel, Nicolaus & Company, Incorporated (incorporated by reference to Exhibit 1.1 to Form 8-K filed with the SEC on April 19, 2021)
(1.2)	At-The-Market Equity Offering Sales Agreement by and between PHX Minerals Inc. and Stifel, Nicolaus & Company, Incorporated, dated August 25, 2021 (incorporated by reference to Exhibit 1.1 to Form 8-K filed with the SEC on August 25, 2021)
(3.1)	Amended and Restated Certificate of Incorporation of PHX Minerals Inc.
(3.2)	Amended and Restated Bylaws of PHX Minerals Inc. (incorporated by reference to Exhibit 3.2 to Form 8-K filed with the SEC on October 13, 2020)
(4.1)	Instruments defining the rights of security holders (incorporated by reference to Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws listed above)
*(10.1)	Amended Indemnification Agreement indemnifying directors and officers (incorporated by reference to Exhibit 10 to Form 8-K filed with the SEC on June 19, 2007)
*(10.2)	Form of Amended and Restated Change-in-Control Executive Severance Agreement (incorporated by reference to Exhibit 10.17 to Form 10-K filed with the SEC on December 10, 2020)
*(10.3)	PHX Minerals Inc. Amended 2010 Restricted Stock Plan (incorporated by reference to Exhibit 10.18 to Form 10-K filed with the SEC on December 10, 2020)
*(10.4)	PHX Minerals Inc. 2021 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on March 8, 2021)
+(10.5)	Purchase and Sale Agreement dated April 14, 2021, by and among PHX Minerals Inc., as Buyer, and Palmetto Investments Partners, LLC, Palmetto Investments Partners II, LLC and Crestwood Exploration Partners, LLC, as Sellers (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on April 15, 2021)
(10.6)	Credit Agreement dated as of September 1, 2021, among PHX Minerals Inc., each lender from time to time party thereto, and Independent Bank, as Administrative Agent and L/C Issuer (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on September 3, 2021)
+(10.7)	Purchase and Sale Agreement dated September 16, 2021, by and among PHX Minerals Inc., as Buyer, and Midnight Resource Partners, LLC and Merrimac Properties Partners, LLC, as Sellers (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on September 16, 2021)
+(10.8)	Purchase and Sale Agreement dated September 16, 2021, by and between PHX Minerals Inc., as Buyer, and Palmetto Investment Partners II, LLC, as Seller (incorporated by reference to Exhibit 10.2 to Form 8-K filed with the SEC on September 16, 2021).
+(10.9)	Purchase and Sale Agreement, dated November 10, 2021, by and between PHX Minerals Inc., as Buyer, and Vendera Resources III, LP and Vendera Management III LLC, collectively as Seller (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on November 12, 2021).
+(10.10)	Purchase and Sale Agreement, dated December 6, 2021, by and among Merrimac Properties Partners, LLC and Quarter Horse Energy Partners, LLC, as Sellers, and PHX Minerals Inc., as Buyer (incorporated by reference to Exhibit 10.1 to Form 8-K filed with the SEC on December 9, 2021).
+(10.11)	Purchase and Sale Agreement, dated December 6, 2021, by and between Palmetto Investment Partners II, LLC, as Seller, and PHX Minerals Inc., as Buyer (incorporated by reference to Exhibit 10.2 to Form 8-K filed with the SEC on December 9, 2021).
(10.12)	First Amendment to Credit Agreement dated as of December 6, 2021, by and among PHX Minerals Inc., each lender party thereto, and Independent Bank, as Administrative Agent and L/C Issuer (incorporated by reference to Exhibit 10.3 to Form 8-K filed with the SEC on December 9, 2021).
(23.1)	Consent of Ernst & Young, LLP
(23.2)	Consent of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(24.1)	Power of Attorney (see signature page)
(31.1)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(31.2)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32.1)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(32.2)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(99)	Report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consultants
(101.INS)	Inline XBRL Instance Document
(101.SCH)	Inline XBRL Taxonomy Extension Schema Document
(101.CAL)	Inline XBRL Taxonomy Extension Calculation Linkbase Document
(101.LAB)	Inline XBRL Taxonomy Extension Labels Linkbase Document
(101.PRE)	Inline XBRL Taxonomy Extension Presentation Linkbase Document
(101.DEF)	Inline XBRL Taxonomy Extension Definition Linkbase Document
(104)	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

*	Indicates management contract or compensatory plan or arrangement

\+ The Purchase and Sale Agreement contains schedules and exhibits that have been omitted pursuant to Item 601(a)(5)
of Regulation S-K. The Company agrees to furnish a supplemental copy of any such omitted exhibit or schedule to
the SEC upon request.

ITEM 16 FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

PHX MINERALS INC.

By: /s/ Chad L. Stephens
Chad L. Stephens
President and Chief Executive Officer

Date: December 13, 2021

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Chad L. Stephens and Ralph D’Amico, with full power of substitution and re-substitution, his or her true and lawful attorney-in-fact and agent, to sign any amendments to this report, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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 and on the dates indicated.

Signature	Title	Date
/s/ Chad L. Stephens Chad L. Stephens	President and Chief Executive Officer	December 13, 2021
/s/Ralph D'Amico Ralph D'Amico	Vice President and Chief Financial Officer	December 13, 2021
/s/ Mark T. Behrman Mark T. Behrman	Lead Independent Director	December 13, 2021
/s/ Lee M. Canaan Lee M. Canaan	Director	December 13, 2021
/s/ Peter B. Delaney Peter B. Delaney	Director	December 13, 2021
/s/ Christopher T. Fraser Christopher T. Fraser	Director	December 13, 2021
/s/ John H. Pinkerton John H. Pinkerton	Director	December 13, 2021
/s/ Glen A. Brown Glen A. Brown	Director	December 13, 2021