UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2022

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: 001-33784

SANDRIDGE ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**20-8084793**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1 E. Sheridan Ave, Suite 500 Oklahoma City, Oklahoma	**73104**
(Address of principal executive offices)	**(Zip Code)**

(405) 429-5500

(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, $0.001 par value	SD	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 Section 15(d) of the Act. Yes ☐ No ☑

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T 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, a 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. 7276(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2022 was approximately $484.5 million based on the closing price as quoted on the New York Stock Exchange. As of March 8, 2023, there were 36,881,377 shares of our common stock outstanding.

Auditor Firm ID:	659	**Auditor Name:**	MOSS ADAMS LLP	**Auditor Location:**	Houston, TX
Auditor Firm ID:	34	**Auditor Name:**	DELOITTE & TOUCHE LLP	**Auditor Location:**	Houston, TX

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's definitive proxy statement for the 2023 Annual Meeting of Stockholders, which will be filed with the SEC within 120 days of December 31, 2022, are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.
2022 ANNUAL REPORT ON FORM 10-K
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GLOSSARY OF TERMS

References in this report to the "Company," "SandRidge," "we," "our," and "us" mean SandRidge Energy, Inc., including its consolidated subsidiaries and variable interest entities of which it is the primary beneficiary. In addition, the following is a description of the meanings of certain terms used in this report.

2020 Credit Facility. Credit facility dated November 30, 2020.

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

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

Bankruptcy Code. United States Bankruptcy Code.

Bankruptcy Court. United States Bankruptcy Court for the Southern District of Texas.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of the Company's reserves at year-end 2022 of $93.67/ Bbl for oil and $6.36/MMBtu for natural gas, the ratio of economic value of oil to natural gas was approximately 15 to 1, even though the ratio for determining energy equivalency is 6 to 1.

Boe/d. Boe per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Ceiling limitation. Present value of future net revenues from proved oil, natural gas and natural gas liquids ("NGL") reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects.

CO_2. Carbon dioxide.

Completion. The process of treating a drilled well, primarily through hydraulic fracturing, followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Counterparty. Counterparty to the Company's derivative agreements.

Debtors. The Company and certain of its direct and indirect subsidiaries which collectively filed for reorganization under the Bankruptcy Code on May 16, 2016.

Developed acreage. The number of acres that are assignable to productive wells.

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

Development costs. Costs incurred to obtain access to proved reserves, complete wells and provide facilities for extracting, treating, gathering and storing oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill, equip and complete development wells, development-type stratigraphic test wells and service wells, including the costs of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

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

Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Emergence Date. Date the Debtors emerged from bankruptcy, October 4, 2016.

Exchange Act. Securities Exchange Act of 1934, as amended.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to produce oil or natural gas in another reservoir.

FASB. 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 and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geological barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal well. A well that is turned horizontally at depth, providing access to oil and gas reserves at a wide range of angles.

Hydraulic fracturing. Procedure to stimulate production by forcing a mixture of fluid and proppant into the formation under high pressure. Hydraulic fracturing creates artificial fractures in the reservoir rock to increase permeability and porosity.

IRS. Internal Revenue Service.

Lease. A contract in which the owner of minerals gives a company or working interest owner temporary and limited rights to explore for, develop, and produce minerals from the property, or; any transfer where the owner of a mineral interest assigns all or a part of the operating rights to another party but retains a continuing nonoperating interest in production from the property.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBoe. Million barrels of oil equivalent.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. MMcf per day.

Mississippian Trust I. SandRidge Mississippian Trust I.

Mississippian Trust II. SandRidge Mississippian Trust II.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

NGL. Natural gas liquids, such as ethane, propane, butane and natural gasoline that are extracted from natural gas production streams.

North Park Basin. NPB or North Park.

NYMEX. The New York Mercantile Exchange.

NYSE. New York Stock Exchange.

Omnibus Incentive Plan. SandRidge Energy, Inc. 2016 Omnibus Incentive Plan.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues. The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10%.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities that become part of the cost of oil and natural gas produced.

Productive well. A well that is found to be capable of producing oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Prospect. A specific geographic area that, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil, natural gas and NGL reserves. Those quantities of oil, natural gas and NGLs 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 estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For additional information, see the SEC's definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC's website.

Proved undeveloped reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion.

PV-10. See "Present value of future net revenues" above.

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

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

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

Royalty Interest. An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas or NGL production. A company or person that owns a royalty interest does not bear any operational costs needed to produce the resource.

Royalty Trust. Individually, the SandRidge Mississippian Trust I and the SandRidge Mississippian Trust II.

Royalty Trusts. Collectively, the SandRidge Mississippian Trust I and the SandRidge Mississippian Trust II.

SEC. Securities and Exchange Commission.

SEC prices. Unweighted arithmetic average oil and natural gas prices as of the first day of the month for the most recent 12 months as of the balance sheet date.

Securities Act. Securities Act of 1933, as amended.

Standardized measure or standardized measure of discounted future net cash flows. The present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs and future income tax expenses and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes on future net revenues.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

Undeveloped oil, natural gas and NGL reserves. 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 completion.

i. 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.

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

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

US GAAP. United States Generally Accepted Accounting Principles.

Warrants. Series A warrants and Series B warrants with initial exercise prices of $41.34 and $42.03 per share, respectively, which expired on October 4, 2022.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Cautionary Note Regarding Forward-Looking Statements

This report includes "forward-looking statements" as defined by the SEC. These forward-looking statements may include projections and estimates concerning our capital expenditures, liquidity, capital resources and debt profile, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of our business strategy, compliance with governmental regulation of the oil and natural gas industry, including environmental regulations, acquisitions and divestitures and the potential effects on our financial condition and other statements concerning our operations, financial performance and financial condition. Forward-looking statements are generally accompanied by words such as "estimate," "assume," "target," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal," "should," "intend" or other words that convey the uncertainty of future events or outcomes. These forward-looking statements are based on certain assumptions and analyses based on our experience and perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected. The Company disclaims any obligation to update or revise these forward-looking statements unless required by law, and cautions readers not to rely on them unduly. While we consider these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks and uncertainties discussed in "Risk Factors" in Item 1A of this report, as well as the following:

- risks associated with drilling oil and natural gas wells;
- the volatility of oil, natural gas and NGL prices;
- uncertainties in estimating oil, natural gas and NGL reserves;
- the need to replace the oil, natural gas and NGL reserves the Company produces;
- our ability to execute operationally by drilling wells as planned or other methods;
- the amount, nature and timing of capital expenditures, including future development costs, required to develop our undeveloped areas;
- concentration of operations in the Mid-Continent region of the United States;
- limitations of seismic data;
- the potential adverse effect of commodity price declines on the carrying value of our oil and natural properties;
- severe or unseasonable weather that may adversely affect production;
- availability of satisfactory oil, natural gas and NGL marketing and transportation options;
- availability and terms of capital to fund capital expenditures including rising interest rates;
- amount and timing of proceeds of asset monetizations;
- potential financial losses or earnings reductions from commodity derivatives;
- potential elimination or limitation of tax incentives or tax losses and/or reduction of Net Operating Loss Carryforwards ("NOLs");
- risks and uncertainties related to the adoption and implementation of regulations restricting oil and gas development in states where we operate;
- competition in the oil and natural gas industry;
- general economic conditions, either internationally or domestically affecting the areas where we operate;
- costs to comply with current and future governmental regulation of the oil and natural gas industry, including environmental, health and safety laws and regulations, and regulations with respect to hydraulic fracturing and the disposal of produced water; and
- the need to maintain adequate internal control over financial reporting.
- the need to protect and maintain the integrity of our Information Technology ("IT") systems and processes from vulnerabilities.

PART I

Item 1. *Business*

GENERAL

We are an independent oil and natural gas company, organized in 2006, with a principal focus on acquisition, development and production activities in the U.S. Mid-Continent.

As of December 31, 2022, we had an interest in 1,471 gross (856 net) producing wells, approximately 992 of which we operate, and approximately 551,000 gross (365,000 net) total acres under lease. As of December 31, 2022, we had one rig drilling. Total estimated proved reserves as of December 31, 2022, were 74.3 MMBoe, all of which were proved developed.

Our principal executive offices are located at 1 E. Sheridan Ave, Suite 500, Oklahoma City, Oklahoma 73104 and our telephone number is (405) 429-5500. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are made available free of charge on our website at www.sandridgeenergy.com as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. Any materials that we have filed with the SEC may be accessed via the SEC's website address at *www.sec.gov*.

Our Business Strategy

The Company's primary strategic focus is to grow the cash value and generation capability of our asset base in a safe, responsible and efficient manner, and will seek to use our net operating loss carry forwards to minimize income taxes and maximize cash flow. We will continue to exercise financial discipline and prudent capital allocation to projects we believe provide a high rate of return in the current commodity price environment, and will remain vigilant and maintain optionality for opportunistic, value-accretive acquisitions and business combinations.

PRIMARY BUSINESS OPERATIONS

A comparative discussion of our 2021 to 2020 operating results can be found in Item 1 "Business" included in our Annual Report on Form 10-K for the year ended December 31, 2021 filed with the SEC on March 10, 2022.

Our primary operations are the development and acquisition of hydrocarbon resources. The following table presents information concerning our operations as of December 31, 2022.

	Estimated Proved Reserves (MMBoe) (1)	Daily Production (MBoe/d)(2)	Reserves/ Production (Years)(3)	Gross Acreage	Net Acreage	Capital Expenditures (In millions) (4)
Geographic Area						
Mid-Continent	74.3	17.7	11.5	551,000	365,000	50.6

(1) Estimated proved reserves were determined using SEC prices, and do not reflect actual prices received or current market prices. All prices are held constant throughout the lives of the properties. The index prices and the equivalent weighted average wellhead prices used in the reserve reports are shown on page 10 below.
(2) Average daily net production for the year ended December 31, 2022.
(3) Estimated proved reserves as of December 31, 2022 divided by net production for the year ended December 31, 2022.
(4) Capital expenditures for the year ended December 31, 2022, on an accrual basis and including acquisitions.

Properties

Mid-Continent

We held interests in approximately 551,000 gross (365,000 net) leasehold acres located primarily in Oklahoma and Kansas at December 31, 2022. Associated proved reserves at December 31, 2022 totaled 74.3 MMBoe, all of which were proved developed reserves. Our interests in the Mid-Continent as of December 31, 2022 included 1,471 gross (856 net) producing wells with an average working interest of 58.2%. The interests are largely aggregated across the Mississippian Lime, Meramec and Osage formations. The Mississippian Lime formation is an expansive carbonate hydrocarbon system located on the Anadarko Shelf in northern Oklahoma and southern Kansas. The top of this formation is encountered between approximately 4,000 and 7,000 feet and stratigraphically between various formations of Pennsylvanian age and the Devonian-aged Woodford Shale formation. The Mississippian formation is approximately 350 to 650 feet in gross thickness across our lease position and has targeted porosity zone(s) ranging between 20 and 150 feet in thickness. The Meramec and Osage Formations are Mississippian in age, lying above the Woodford Shale and below Chester formations. The Meramec is composed of interbedded shales, sands, and carbonates while the Osage is composed of low porosity, fractured limestone and chert. The top of these target formations ranges in depth from about 5,800 feet at the northern edge of the basin to greater than 14,000 feet toward the interior of the basin. Meramec formation thickness ranges from about 50 feet to over 400 feet and the Osage formation thickness ranges from about 450 to 1,400 feet. The Woodford Shale is the primary hydrocarbon source for both the Meramec and Osage.

Proved Reserves

The portion of a reservoir considered to contain proved reserves includes (i) the portion 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, natural gas or NGLs 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 establish a lower contact with reasonable certainty.

Existing economic conditions include prices, costs, operating methods and government regulations existing at the time the reserve estimates are made. SEC prices are used to determine proved reserves, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. See further discussion of prices in "Risk Factors" included in Item 1A of this report.

Preparation of Reserves Estimates

Approximately 95 percent of the proved oil, natural gas and NGL reserves disclosed in this report have been independently prepared by Cawley, Gillespie & Associates ("CGA"), a leader of petroleum property analysis for industry and financial institutions. CGA was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 18, 2023, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 35 years of practical experience in petroleum engineering, with over 33 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

The primary technical person responsible for preparing the reserve estimates within the Company is Mr. Eric Allen, the Reservoir Engineering Manager. Mr. Allen graduated from Oklahoma State University with a Bachelor of Science in Chemical Engineering in 2010 and has been practicing petroleum engineering since graduating. In 2016 Mr. Allen graduated from the University of Oklahoma with a Master's in Business Administration. Mr. Allen has over 13 years of practical experience in petroleum engineering with 8 of those years having been spent in the estimation and evaluation of reserves. Since 2016, Mr. Allen has been a Registered Professional Engineer in the State of Oklahoma (License No. 29209) and is an active member of the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

To establish reasonable certainty with respect to our estimated proved reserves, the independent and internal reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used to estimate our proved reserves include, but are not limited to, well logs, geological maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. This data was reviewed by various levels of management for accuracy before consultation with independent reserve engineers. This consultation included review of properties, assumptions and available data. Internal reserve estimates were compared to those prepared by independent reserve engineers to test the estimates and conclusions before the reserves were included in this report. The accuracy of the reserve estimates is dependent on many factors, including the following:

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

The Reservoir Engineering Manager serves as the primary technical professional providing oversight of our reserve estimate. CGA and the Reservoir Engineering Manager monitor well performance and make reserve estimate adjustments as necessary to ensure the most current information is reflected.

We encourage ongoing professional education for our engineers and analysts on new technologies and industry advancements as well as refresher training on basic skill sets.

In order to ensure the reliability of reserves estimates, SandRidge has a comprehensive SEC-compliant internal controls framework and set of policies to determine, estimate and report proved reserves including:

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

Key reserve information is reviewed and approved at least annually by the Company's Chief Executive Officer and Chief Financial Officer.

SandRidge's reserve engineers and the Reservoir Engineering Manager work closely with independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserve estimates are presented to the Audit Committee of the Board of Directors ("Audit Committee"). In addition to reviewing the independently developed reserve reports, the Audit Committee also periodically meets with the independent petroleum consultants that prepare estimates of proved reserves.

The percentage of total proved reserves prepared by each of the independent petroleum consultants is shown in the table below.

	December 31,	
	2022	**2021**
Cawley, Gillespie & Associates, Inc.	95.0 %	96.2 %
Total	95.0 %	96.2 %

The remaining 5.0% and 3.8% of estimated proved reserves as of December 31, 2022 and 2021, respectively, were based on internally prepared estimates.

A copy of the report issued by our independent reserve consultant with respect to our oil, natural gas and NGL reserves as of December 31, 2022 is filed with this report as Exhibit 99.1. Cawley, Gillespie & Associates prepared reserves for our Mid-Continent properties located in Kansas and Oklahoma as of December 31, 2022.

Reporting of Natural Gas Liquids

NGLs are recovered through further processing of a portion of our natural gas production stream. At December 31, 2022, NGLs comprised approximately 34% of total proved reserves on a barrel equivalent basis and represented volumes to be produced from properties where we have contracts in place for the extraction and sale of NGLs. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, we have included production and reserves in barrels based on a conversion rate of 42 gallons per barrel. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. The amount of NGLs extracted from produced gas can vary with individual component prices and we have limited direct control over the extent to which NGLs are extracted from our natural gas, particularly light-end components such as ethane. All production information related to natural gas is reported net of the effect of any reduction in natural gas volumes resulting from the processing and extraction of NGLs.

Reserve Quantities, PV-10 and Standardized Measure

The following estimates of proved oil, natural gas and NGL reserves are based on reserve reports as of December 31, 2022 and 2021 approximately 95% and over 96%, respectively, of which were prepared by independent reserve engineers.

See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31, 2022	December 31, 2021
Estimated Proved Reserves (1)		
Developed		
Oil (MMBbls)	8.4	7.9
NGL (MMBbls)	25.4	24.3
Natural gas (Bcf)	242.8	234.7
Total proved developed (MMBoe)	74.3	71.3
Undeveloped		
Oil (MMBbls)	—	—
NGL (MMBbls)	—	—
Natural gas (Bcf)	—	—
Total proved undeveloped (MMBoe)	—	—
Total Proved		
Oil (MMBbls)	8.4	7.9
NGL (MMBbls)	25.4	24.3
Natural gas (Bcf)	242.8	234.7
Total proved (MMBoe)	74.3	71.3
Standardized Measure of Discounted Net Cash Flows (in millions) (2)	$ 806.9	$ 432.9
PV-10 (in millions) (3)	$ 810.7	$ 432.9

(1) Estimated proved reserves, PV-10 and Standardized Measure were determined using SEC prices, and do not reflect actual prices received or current market prices. All prices are held constant throughout the lives of the properties.

The index prices and the equivalent weighted average wellhead prices used in the reserve reports are shown in the table below:

	Index prices (a)		Weighted average wellhead prices (b)		
	Oil (per Bbl)	Natural gas (per MMBtu)	Oil (per Bbl)	NGL (per Bbl)	Natural gas (per Mcf)
December 31, 2022	$ 93.67	$ 6.36	$ 93.73	$ 33.42	$ 4.76
December 31, 2021	$ 66.56	$ 3.60	$ 64.95	$ 19.26	$ 2.56

(a) Index prices are based on average WTI Cushing spot prices for oil and average Henry Hub spot market prices for natural gas. These are SEC prices calculated by using trailing 12 month average from the first trading day close of each calendar month.

(b) Average adjusted volume-weighted wellhead product prices reflect adjustments for transportation, quality, gravity, regional price differentials and excludes any impact of derivatives.

(2) Standardized Measure differs from PV-10 as standardized measure includes the effect of future income taxes. At December 31, 2021 there was no difference between the standardized measure and PV-10 due to an excess of tax basis in oil and natural gas properties over projected undiscounted future cash flows from our proved reserves.

(3) PV-10 is a non-GAAP financial measure. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our oil and natural gas properties. PV-10 is used by the industry and by management as a reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities.

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

	December 31,			
	2022		2021	
	(In thousands)			
PV-10	$	810,663	$	432,914
Present value of future income tax discounted at 10%	$	(3,798)	$	—
Standardized Measure of Discounted Net Cash Flows	$	806,865	$	432,914

Proved Reserves - Mid-Continent. Proved reserves increased from 71.3 MMBoe at December 31, 2021 to 74.3 MMBoe at December 31, 2022, primarily as a result of positive revisions of 9.1 MMBoe associated with the increase in year-end SEC commodity prices for oil and natural gas, 1.8 MMBoe related to the Company's well reactivation program, and 1.0 MMBoe associated with other commercial improvements. Further, extensions added 1.2 MMBoe and purchases added 0.2 MMBoe of proved reserves. These increases were partially offset by 2022 production totaling 6.5 MMBoe, a decrease of 1.0 MMBoe due to higher operating expenses in the trailing twelve month period used in the projections, and a decrease of 2.8 MMBoe attributable to other revisions.

Proved Undeveloped Reserves.

There were no proved undeveloped reserves at December 31, 2022 and 2021.

For additional information regarding changes in proved reserves during each of the three years ended December 31, 2022, 2021 and 2020 see "Note 20—Supplemental Information on Oil and Natural Gas Producing Activities" to the accompanying consolidated financial statements in Item 8 of this report.

Production and Price History

The following table includes information regarding our net oil, natural gas and NGL production and certain price and cost information for each of the periods indicated. For the year ended December 31, 2021, NPB had 67 MBoe in oil production.

	Year Ended December 31,	
	2022	2021
Production data (in thousands)		
Oil (MBbls)	949	957
NGL (MBbls)	1,997	2,267
Natural gas (MMcf)	21,101	21,417
Total volumes (MBoe)	6,463	6,793
Average daily total volumes (MBoe/d)	17.7	18.6
Average prices—as reported (1)		
Oil (per Bbl)	$ 92.21	$ 65.10
NGL (per Bbl)	$ 31.88	$ 22.42
Natural gas (per Mcf)	$ 4.88	$ 2.60
Total (per Boe)	$ 39.34	$ 24.86
Expenses per Boe		
Production costs (2)	$ 6.39	$ 5.30

(1) Prices represent actual average prices for the periods presented and do not include effects of derivative transactions.
(2) Represents production costs per Boe excluding production and ad valorem taxes.

Productive Wells

The following table presents the number of productive wells in which we owned a working interest at December 31, 2022. We operate the majority of all wells in which we owned a working interest at December 31, 2022 and 2021. Productive wells consist of wells that are currently producing hydrocarbons. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of the fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Geographic Area						
Mid-Continent	1,146	653	325	203	1,471	856

Drilling Activity

During the year ended December 31, 2022 there were eight operated wells drilled, with one third-party rig actively drilling on our operated acreage and two wells awaiting completion. Additionally, we participated in one non-operated well drilled for the year ended December 31, 2022. During the year ended December 31, 2021, there were no operated wells drilled. There were no third-party rigs drilling on our operated acreage at December 31, 2021 or any wells awaiting completion and we did not participate in any non-operated wells drilled for the year ended December 31, 2021.

Developed and Undeveloped Acreage

The following table presents information regarding our developed and undeveloped acreage at December 31, 2022.

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Geographic Area				
Mid-Continent	487,402	338,176	63,196	27,011

Less than 5% of the leases included in the undeveloped acreage above will expire at the end of their respective primary terms. To prevent expiration, we may exercise our contractual rights to extend the terms of leases we value or may establish production from the leasehold acreage prior to expiration, which would keep the lease from expiring until production has ceased.

As of December 31, 2022, the gross and net acres subject to leases in the undeveloped acreage above are set to expire as follows:

	Acres Expiring	
	Gross	Net
Twelve Months Ending		
December 31, 2023	158	13
December 31, 2024	162	140
December 31, 2025	475	316
December 31, 2026 and later	566	305
Total (1)	1,361	774

(1) The Company has 61,835 gross (26,237 net) undeveloped acres not subject to expiration.

Marketing

We sell our oil, natural gas and NGLs to a variety of customers, including oil and natural gas companies and trading and energy marketing companies. We had two purchasers that each individually accounted for more than 10% of our total revenue during the year ended December 31, 2022. See "Note 1—Summary of Significant Accounting Policies" to the accompanying consolidated financial statements in Item 8 of this report for additional information on our major customers. The number of available purchasers and markets in the areas where we sell our production reduces the risk that loss of a single downstream customer would materially affect our sales. We do not have any material commitments to deliver fixed and determinable quantities of oil and natural gas in the future under existing sales contracts or sales agreements.

Title to Properties

As is customary in the oil and natural gas industry, we conduct a preliminary review of the title to our properties. Prior to commencing drilling operations on our properties, we conduct a thorough title examination and perform curative work with respect to significant defects, typically at our expense. In addition, prior to completing an acquisition of producing oil and natural gas assets, we perform title reviews on the most significant leases and depending on the materiality of properties, may obtain a drilling title opinion or review previously obtained title opinions. To date, we have obtained drilling title opinions on substantially all of our producing properties and believe that we have good and defensible title to our producing properties. Our oil and natural gas properties are subject to customary royalty and other interests, and liens for current taxes and other burdens, which we believe does not materially interfere with the use of, or affect the carrying value of the properties.

COMPETITION

We compete with other oil and natural gas companies for leases, equipment, personnel and markets for the sale of oil, natural gas and NGLs. We believe our leasehold acreage position, geographic concentration of operations and technical and operational capabilities enable us to compete with other oil and gas development and production companies. However, the oil and natural gas industry is intensely competitive. See "Item 1A. Risk Factors" for additional discussion of competition in the oil and natural gas industry.

Oil, natural gas and NGLs compete with other forms of energy available to customers, including alternate forms of energy such as wind, solar, and nuclear generated electricity, coal and biofuels. Changes in the availability or price of oil, natural gas and NGLs or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil, natural gas and NGLs.

SEASONAL NATURE OF BUSINESS

Generally, demand for natural gas decreases during the summer months and increases during the winter months and demand for oil peaks during the summer months. Certain natural gas purchasers utilize natural gas storage facilities and acquire some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for meeting our well drilling objectives, delay the installation of production facilities, and increase competition for equipment, supplies and personnel during certain times of the year, which could lead to shortages and increase costs or delay operations.

ENVIRONMENTAL REGULATIONS

General

Our oil and natural gas development operations are subject to stringent and complex federal, state, tribal, regional and local laws and regulations governing, among other factors, worker safety and health, the discharge and disposal of substances into the environment, and the protection of the environment and natural resources. Numerous governmental entities, including the EPA and analogous state and local agencies, (and, under certain laws, private individuals) have the power to enforce compliance with these laws and regulations and any permits issued under them. These laws and regulations may, among other things: (i) require permits to conduct exploration, drilling, water withdrawal, wastewater disposal and other production related activities; (ii) govern the types, quantities and concentrations of substances that may be disposed or released into the environment or injected into formations in connection with drilling or production activities, and the manner of any such disposal, release, or injection; (iii) limit or prohibit construction or drilling activities or require formal mitigation measures in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; (iv) require investigatory and remedial actions to mitigate pollution conditions arising from the Company's operations or attributable to former operations; (v) impose safety and health restrictions designed to protect employees and others from exposure to hazardous or dangerous substances; and (vi) impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects and the issuance of orders enjoining operations in affected areas.

The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment. Any changes in or more stringent enforcement of these laws and regulations that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management or completion activities or waste handling, storage, transport, remediation, or disposal emission or discharge requirements could have a material adverse effect on the Company. For example, on January 20, 2021, the Biden Administration placed a 60-day moratorium on new oil and gas leasing and drilling permits on federal land. In June 2021, a nationwide preliminary injunction was issued by the United States District Court in the Western District of Louisiana against the provisions of President Biden's Executive Order 14008 that blocked oil and gas leasing operations on federal lands. In August 2022, the U.S. Court of Appeals for the 5th Circuit vacated and remanded the District Court's decision for further clarification, allowing the moratorium to remain in effect. These actions could adversely impact our business and our industry generally, particularly if the moratorium continues to be extended. Further, we may be unable to pass on increased environmental compliance costs to our customers. Moreover, accidental releases, including spills, may occur in the course of our operations, and there can be no assurance that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property and natural resources or personal injury. While we do not believe that compliance with existing environmental laws and regulations and that continued compliance with existing requirements will have an adverse material effect on us, we can provide no assurance that we will not incur substantial costs in the future related to revised or additional environmental regulations that could have a material adverse effect on our business, financial condition, and results of operations.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on the Company.

Hazardous Substances and Wastes

We currently own, lease, or operate, and in the past have owned, leased, or operated, sold or transferred properties that have been used in the exploration and production of oil and natural gas. We believe we have utilized operating and disposal practices that were standard in the industry at the applicable time, but hazardous substances, hydrocarbons, and wastes may have been disposed or released on, from or under the properties owned, leased, or operated by us or on or under other locations where these substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose storage treatment and disposal or release of hazardous substances, hydrocarbons, and wastes were not under our control. These properties and the substances or wastes disposed or released on them may be subject to the Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), the federal Resource Conservation and Recovery Act, ("RCRA"), and analogous state laws. Under these laws, we could be required to investigate, monitor, remove or remediate previously disposed substances or wastes (including substances or wastes disposed of or released by prior owners or operators or third parties whose waste was commingled with ours), to investigate and clean up contaminated property, to perform corrective actions, to prevent future contamination, or to pay some or all of the costs of any such action.

CERCLA, also known as the Superfund law, and comparable state laws may impose strict, joint and several liability without regard to fault or legality of conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release of a hazardous substance occurred as well as entities that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these "potentially responsible parties" may be liable for the costs of cleaning up sites where the hazardous substances have been released into the environment, for damages to natural resources resulting from the release and for the costs of certain environmental and health studies. Additionally, landowners and other third parties may file claims for personal injury and natural resource and property damage allegedly caused by the release of hazardous substances into the environment. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment from a hazardous substance release and to pursue steps to recover costs incurred for those actions from responsible parties. Although petroleum, natural gas and natural gas liquids are excluded from the definition of "hazardous substance" under CERCLA, despite this so-called "petroleum exclusion," certain products used in the course of our operations may be regulated as CERCLA hazardous substances. To date, no Company-owned or operated site has been designated as a Superfund site, and we have not been identified as a responsible party for any Superfund site.

We also generate wastes that are subject to the requirements of RCRA and comparable state statutes. RCRA imposes strict "cradle-to-grave" requirements on the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Drilling fluids, produced waters and other wastes associated with the exploration, production and/or development of oil and natural gas, including naturally-occurring radioactive material, if properly handled, are currently excluded from regulation as hazardous wastes under RCRA and, instead, are regulated under RCRA's less stringent non-hazardous waste requirements. However, it is possible that these wastes could be classified as hazardous wastes in the future. Any change in the exclusion for such wastes could potentially result in an increase in costs to manage and dispose of wastes which could have a material adverse effect on our results of operations and financial position.

Air Emissions

The federal Clean Air Act (the "CAA"), as amended, and comparable state laws and regulations restrict the emission of air pollutants through emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permit requirements or utilize specific equipment or technologies to control emissions. For example, in June 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities to be aggregated for permitting purposes, resulting in treatment as a major source, and thereby triggering more stringent air permitting requirements. The need to acquire such permits has the potential to delay or limit the development of our oil and natural gas projects.

Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standards for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare. In November 2017, the EPA published a list of areas that are in compliance with the new ozone standards and separately in December 2017 issued responses to state recommendations for designating non-attainment areas. In November 2018, the EPA issued final rules implementing the non-attainment area designations. While the EPA has determined that all counties in which we operate are in attainment with the 2015 ozone standard, these determinations may be revised in the future. On December 31, 2020, EPA published its decision to retain the 2015 ozone standards; however, the Biden Administration has announced that it intends to review this rule under President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*. EPA has announced that it is targeting the end of 2023 to complete its reconsideration of the 2015 ozone standards and intends to reinstall the ozone panel of the Clean Air Scientific Advisory Committee to advise the Administration. Further reductions in the ozone National Ambient Air Quality Standards could affect our operations and result in the need to install new emissions controls, longer permitting timelines and significant increases in our capital or operating expenditures. Compliance with these and any future air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which could be significant.

Water Discharges

The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act (the "CWA"), and analogous state laws and implementing regulations, impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States. Pursuant to these laws and regulations, the discharge of pollutants into regulated waters is prohibited unless it is permitted by the EPA, the Army Corps of Engineers ("Corps") or an analogous state or tribal agency. We do not presently discharge pollutants associated with the exploration, development and production of oil and natural gas into federal or state waters. The CWA and analogous state laws and regulations also impose restrictions and controls regarding the discharge of sediment via storm water run-off from a wide variety of construction activities. Such activities are generally prohibited from discharging sediment unless permitted by the EPA or an analogous state agency.

The scope of EPA's and the Corps' regulatory authority under Section 404 of the CWA has been the subject of extensive litigation and frequently changing regulations. The EPA issued a final rule in September 2015 that attempted to clarify the federal jurisdictional reach over waters of the United States ("WOTUS") under Section 404 of the CWA. The EPA and the Corps then proposed a rulemaking in June 2017 to repeal the June 2015 WOTUS rule and also announced their intent to issue a new rule redefining the term WOTUS as used in the CWA. On October 22, 2019, EPA and the Corps published a final rule repealing the 2015 WOTUS rule, and EPA and the Corps promulgated the Navigable Waters Protection Rule on April 21, 2020, which provides a revised definition of WOTUS and became effective on June 22, 2020. These regulations have been challenged in federal court, and on August 30, 2021 the U.S. District Court for the District of Arizona vacated and remanded the Navigable Waters Protection Rule. On December 7, 2021, EPA and the Corps issued a proposed rule to revise the definition of WOTUS. A year later on December 30, 2022, the agencies announced a final rule which will take effect 60 days after publication in the Federal Register. In the fall of 2022, the agencies announced that they intend to consider further refinements to the definition of WOTUS in a second rule that would take into account additional stakeholder engagement and implementation considerations, scientific developments, and environmental justice values. The agencies intend to propose the second rule toward the end of 2023, with the final rule published by July 2024. The future regulations concerning the definition of WOTUS may result in an expansion of the scope of the CWA's jurisdiction, and we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas or other WOTUS in connection with our operations. Also, in June 2016, the EPA issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs.

Finally, the Oil Pollution Act of 1990 ("OPA"), which amends the CWA, establishes standards for prevention, containment and cleanup of oil spills into waters of the United States. The OPA requires measures to be taken to prevent the accidental discharge of oil into waters of the United States from onshore production facilities. Measures under the OPA and/or the CWA include inspection and maintenance programs to minimize spills from oil storage and conveyance systems; the use of secondary containment systems to prevent spills from reaching nearby water bodies; proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill; and the development and implementation of spill prevention, control and countermeasure ("SPCC") plans to prevent and respond to oil spills. The OPA also subjects owners and operators of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill. We have developed and implemented SPCC plans for properties as required under the CWA.

Subsurface Injections

Underground injection operations performed by us are subject to the Safe Drinking Water Act ("SDWA"), as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control ("UIC") program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require a permit from the applicable regulatory agencies to operate underground injection wells. Although the Company monitors the injection process of its wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third-parties claiming damages for alternative water supplies, property damages and personal injuries. Some states have considered laws mandating flowback and produced water recycling. Other states have undertaken studies, in some cases such as New Mexico in conjunction with the EPA, to assess the feasibility of recycling produced water on a large scale. If such laws are adopted in areas where we conduct operations, our operating costs may increase significantly.

Furthermore, in response to past seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have restricted, suspended or shut down the use of such disposal wells. For example, in Oklahoma, the Oklahoma Corporation Commission ("OCC") has implemented a variety of measures including adopting the National Academy of Science's "traffic light system," pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted. The OCC also evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. In addition, the OCC has issued rules requiring operators of certain saltwater disposal wells in the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells' depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for wells within areas of interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. For example, in February 2016, the OCC issued a plan to reduce disposal well volume in the Arbuckle formation by 40 percent, covering approximately 5,281 square miles and 245 disposal wells injecting wastewater into the Arbuckle formation. In the plan, the OCC identified 76 SandRidge-operated disposals wells, prescribed a four stage volume reduction schedule and set April 30, 2016 as the final date for compliance with the tiered volume reduction plan. In March 2016, the OCC reduced the injection volume of additional Arbuckle disposal wells, including wells we operate. Following earthquakes in August, September and November 2016, the OCC and the EPA further limited the disposal volumes that can be disposed in Arbuckle wells, although these actions did not cover our disposal wells. While induced seismic events generally decreased in 2017, the OCC expanded restrictions on the use of existing Arbuckle disposal wells and imposed new reporting requirements related to disposal volumes on wells injecting produced water into the Arbuckle formation. In February 2018, the OCC instituted a new protocol to further address seismicity in the Sooner Trend Anadarko Basin Canadian and Kingfisher County and South Central Oklahoma Oil Province Plays which requires various actions, such as a pause in operations for several hours, when certain seismic data is observed. These and similar future protocols that may be adopted in response to future seismicity concerns may reduce the productivity of our operations in relevant areas.

Additionally, the Governor of Kansas has established the State Task Force on Induced Seismicity, composed of various administrative agencies, to study and develop an action plan for addressing seismic activity in the state. The task force issued a recommended Seismic Action Plan calling for enhanced seismic monitoring and the development of a seismic response plan, and in November 2014, the Governor of Kansas announced a plan to enhance seismic monitoring in the state. In March 2015, the Kansas Corporation Commission issued its Order Reducing Saltwater Injection Rates (the "Order"). The Order identified five areas of heightened seismic concern within Harper and Sumner Counties and mandated that, within 100 days of the Order's issuance, operators must limit saltwater injection volumes to no more than 8,000 barrels per day for any well located in one of these five areas. SandRidge and other operators of injection wells were required to reduce the injection volume, and any injection well drilled deeper than the Arbuckle Formation was required to be plugged back to a shallower formation in a manner approved by the Kansas Corporation Commission. In August 2016, the Kansas Corporation Commission issued an order that put a 16,000 barrels per day limit on additional Arbuckle disposal wells not previously identified in the Order. While no additional regulatory actions have been taken in Kansas with respect to induced seismicity concerns since 2017, permit applications for new saltwater disposal well facilities have faced increased local opposition.

Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt water disposal activities occur or are proposed to be performed. The adoption of any new laws, regulations, or directives that restrict our ability to dispose of saltwater generated by production and development activities , whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring us to shut down disposal wells, could significantly increase our costs to manage and dispose of this saltwater, which could negatively affect the economic lives of the affected properties. In addition, we could find ourselves subject to third party lawsuits alleging damages resulting from seismic events that occur in our areas of operation.

Climate Change

In December 2009, the EPA published its findings that emissions of CO_2, methane and certain other "greenhouse gases" ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit requirements for GHG emissions from certain large stationary sources that already are major sources of criteria pollutants under the CAA. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In addition, the EPA has adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities on an annual basis, as well as reporting GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing.

In June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, including implementation of a leak detection and repair ("LDAR") program to minimize methane emissions, under the CAA's New Source Performance Standards in 40 C.F.R. Part 60, Subpart OOOOa ("Quad Oa"). On April 18, 2017, the EPA announced its intention to reconsider certain aspects of those regulations, and in June 2017, the EPA proposed a two-year stay of certain requirements of the Quad Oa regulations. In October 2018, the EPA proposed revisions to Quad Oa, such as changes to the frequency for monitoring fugitive emissions at well sites and changes to requirements that a professional engineer certify that meeting certain Quad Oa requirements is technically infeasible. The EPA proposed further revisions to Quad Oa on September 24, 2019, including rescinding the methane requirements in Quad Oa that apply to sources in the production and processing segments of the industry. In September 2020, the EPA finalized amendments to Quad Oa that rescind requirements for the transmission and storage segment of the oil and natural gas industry and rescind methane-specific limits that apply to the industry's production and processing segments, among other things. The Biden Administration announced that it intends to review the September 2020 rules under President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis.* On June 30, 2021, Congress issued a joint resolution pursuant to the Congressional Review Act disapproving the September 2020 rule, and on November 15, 2021, EPA issued a proposed rule to revise the Quad Oa regulations that, if finalized, would require methane emissions reductions and implementation of a fugitive emissions monitoring and repair program. On November 8, 2022, EPA issued a supplemental notice of proposed rulemaking that would impose standards for certain sources that were not addressed in the November 2021 proposal, revise the previously proposed emissions standards, and establish a "super emitter response program" allowing local regulatory agencies and EPA-certified third parties to issue notices to owners and operators of regulated facilities when they detect a so-called "super-emitting event." The EPA is expected to finalize the rulemaking in late 2023. It is possible that these rules and future revisions thereto will continue to require oil and gas operators to expend material sums.

In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and natural gas operations on federal lands that are substantially similar to the EPA Quad Oa requirements. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule, which became effective on November 27, 2018. Both the 2016 and the 2018 rule were challenged in federal court. On July 21, 2020, a Wyoming federal court vacated almost all of the 2016 rule, including all provisions relating to the loss of gas through venting, flaring, and leaks, and on July 15, 2020, a California federal court vacated the 2018 rule. As a result of these decisions, the 1979 regulations concerning venting, flaring and lost production on federal land have been reinstated. On November 28, 2022, the BLM announced a new proposed rule regulating emissions of methane in connection with the production of oil and gas on federal and Tribal lands. If finalized, the proposed rule would require various technology upgrades, impose limits related to flaring, and require LDAR plans. The final rule is expected to be announced later this year. Notably, several states where we operated as of December 31, 2022, have already adopted rules requiring operators of both new and existing sources to develop and implement an LDAR program and to install devices on certain equipment to capture 95 percent of methane emissions. We have the necessary equipment (pollution control equipment and optical gas imaging equipment for LDAR inspections) and personnel trained to assist with the inspection and reporting requirements to maintain compliance with these rules.

In addition, a number of state and regional efforts are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measure each country will use to achieve its GHG emissions targets, (the "Paris Agreement"). However, the Paris Agreement does not impose any binding obligations on the United States. In June 2017, the United States announced it would withdraw from the Paris Agreement, which became effective November 4, 2020. The United States has rejoined the Paris Agreement as of February 19, 2021. Further, several states and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the Paris Agreement. Several pieces of legislation were introduced before the 117th Congress, including the Climate Emergency Act of 2021, which would have directed the President to declare a national emergency relating to climate change and ensure that the federal government invests in projects to mitigate and reduce greenhouse gas emissions. The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require additional expenditures to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves.

Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities or increase the costs of such funding. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time.

Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on the Company and potentially subject the Company to further regulation.

Endangered or Threatened Species

The federal Endangered Species Act (the "ESA") restricts activities that may affect endangered or threatened species or their habitats without first obtaining an incidental take permit and implementing mitigation measures. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act and to bald and golden eagles under the Bald and Golden Eagle Protection Act. While compliance with the ESA has not had an adverse effect on our exploration, development and production operations in areas where threatened or endangered species or their habitat are known to exist, it may require us to incur increased costs to implement mitigation or protective measures and also may delay, restrict or preclude drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. In addition, certain of our federal and state leases may contain stipulations that require us to take measures to safeguard certain species.

The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves. A critical habitat designation could result in further material restrictions to federal and private land use and could delay or prohibit land access or development.

Employee Health and Safety

Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA Hazard Communication Standard requires us to maintain information concerning hazardous materials used or produced in our operations and to provide this information to employees and various entities. Pursuant to the Federal Emergency Planning and Community Right-to-Know Act, facilities that store threshold amounts of chemicals that are subject to OSHA's Hazard Communication Standard must submit information regarding those chemicals by March 1 of each year to state and local authorities in order to facilitate emergency planning and response. That information is generally available to employees, state and local governmental authorities, and the public. We do not believe that compliance with applicable laws and regulations relating to worker health and safety will have a material adverse effect on our business and results of operations.

State and Other Regulation

The states in which we operate, along with some municipalities and Native American tribal areas, regulate some or all of the following activities: the drilling for, and the production and gathering of, oil and natural gas, including requirements relating to drilling permits, the location, spacing and density of wells, unitization and pooling of interests, the method of drilling, casing and equipping of wells, the protection of fresh water sources, the orderly development of common sources of supply of oil and natural gas, the operation of wells, allowable rates of production, the use of fresh water in oil and natural gas operations, saltwater injection and disposal operations, the plugging and abandonment of wells and the restoration of surface properties, the prevention of waste of oil and natural gas resources, the protection of the correlative rights of oil and natural gas owners and, where necessary to avoid unfair, unjust or discriminatory service, the fees, terms and conditions for the gathering of natural gas. These regulations may affect the number and location of our wells and the amounts of oil and natural gas that may be produced from our wells, and increase the costs of our operations. Moreover, obtaining or renewing permits and other approvals for operating on Native American lands can take substantial amounts of time, and could result in increased costs or delays to our operations.

Hydraulic Fracturing

Hydraulic fracturing is a practice in the oil and natural gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. Oil and natural gas may be recovered from certain of our oil and natural gas properties through the use of hydraulic fracturing, combined with sophisticated drilling. Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted federal regulatory authority over certain aspects of the hydraulic fracturing process. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued the Quad Oa regulations for the oil and natural gas industry under the CAA, as described above; and in June 2016 issued final effluent limitations guidelines under the CWA that waste water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant. The EPA also issued an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act ("TSCA") in 2014 regarding reporting of the chemical substances and mixtures used in hydraulic fracturing but, to date, has taken no further action. Separately, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. The U.S. District Court of Wyoming struck down this rule in June 2016. The June 2016 decision was appealed by the BLM to the U.S. Circuit Court of Appeals for the Tenth Circuit. However, following issuance of a presidential executive order to review rules related to the energy industry, in July 2017, the BLM published a proposed rule to rescind the 2015 final rule. In September 2017, the Tenth Circuit issued a ruling to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in light of the BLM's proposed rulemaking. The BLM issued a final rule repealing the 2015 hydraulic fracturing rule in December 2017.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears uncertain. At the state level, some states, including Oklahoma and Kansas, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure, operational or well construction requirements on hydraulic fracturing activities, or that prohibit hydraulic fracturing altogether. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the local, state or federal level, our fracturing activities could become subject to additional permit and financial assurance requirements, more stringent construction requirements, increased reporting or plugging and abandoning requirements or operational restrictions, and associated permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable, and could cause us to incur substantial compliance costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

In addition to asserting regulatory authority, certain government agencies have conducted reviews focusing on environmental issues associated with hydraulic fracturing practices. For example, the EPA released its final report, *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States*, regarding the potential impacts of hydraulic fracturing on drinking water resources in December 2016. The EPA report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water sources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

We diligently review best practices and industry standards and comply with all regulatory requirements in the protection of potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources. We are not aware of any incidents, citations or suits related to our hydraulic fracturing activities involving material environmental concerns.

OTHER REGULATION OF THE OIL AND NATURAL GAS INDUSTRY

The oil and natural gas industry is extensively regulated by numerous federal, state, local, and regional authorities, as well as Native American tribes. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations affecting the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases the Company's cost of doing business and, consequently, affects its profitability, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The price of oil, natural gas and NGLs is not currently regulated and are made at market prices. Although oil, natural gas and NGL prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil, natural gas and NGL prices might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations.

Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels that include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where we operate regulate one or more of the following activities:

- the location of wells;

- the method of drilling and casing wells;
- the timing of construction or drilling activities;
- the rates of production, or "allowables";
- the use of surface or subsurface waters;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas, and NGLs within its jurisdiction.

State agencies in Kansas and Oklahoma impose financial assurance requirements on operators. The Corps and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration.

Natural Gas Sales and Transportation

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 (the "NGA") and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005 (the "EPAct 2005"), the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties in excess of one million dollars per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by the FERC as a natural gas company under the NGA, we are required to report aggregate volumes of natural gas purchased or sold at wholesale to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. In addition, Congress may enact legislation or the FERC may adopt regulations that may subject certain of our otherwise non-the FERC jurisdictional facilities to further regulation. Failure to comply with those regulations in the future could subject us to civil penalty liability.

The Commodity Futures Trading Commission (the "CFTC") also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. The CFTC also holds substantial enforcement authority, including the ability to assess civil penalties in excess of one million dollars per day per violation.

The FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Currently, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. The FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, the less stringent regulatory approach currently pursued by the FERC and Congress might not continue indefinitely into the future. The Company is unable to determine what effect, if any, future regulatory changes might have on the Company's natural gas related activities.

Under the FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in-state waters. Although its policy is still in flux, in the past the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our cost of transporting gas to point-of-sale locations.

Oil and NGL Sales and Transportation Rates

Sales prices of oil and NGLs are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (the "FTC") prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties in excess of one million dollars per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Some of our transportation of oil, natural gas and NGLs is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of crude oil and natural gas liquids transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

HUMAN CAPITAL

As of March 8, 2023 and December 31, 2022, we had 102 full-time employees, including 87 field employees and 15 corporate employees. We had 101 full-time employees, including 85 field employees and 16 corporate employees at December 31, 2021.

Health, Safety and Environment

Our people are a key driver to our success in Health, Safety and Environment ("HSE") related outcomes. Our HSE policy includes a commitment to provide safe and healthy working conditions for the prevention of work-related injury and ill health and is appropriate for the purpose, size and context of the organization. As part of our HSE policy, we aim to identify and correct any work practices that pose an HSE risk to our employees. The Company is devoted to creating a sustainable environment and implementing process improvements for both health and safety and the environment. We evaluate our processes to ensure our protection schemes and work practices minimize these risks. Furthermore, we routinely evaluate our HSE processes, systems, equipment and other factors to ensure they remain aligned with our focus on risk reduction and get us closer to zero incidents.

During 2022, our experience and continuing focus on workplace safety has enabled us to preserve business continuity without sacrificing our commitment to keeping our colleagues and workplace visitors safe during the COVID-19 pandemic.

Item 1A. *Risk Factors*

An investment in our common stock involves certain risks. If any of the following key risks were to develop into actual events, it could have a material adverse effect on our financial position, results of operations and cash flows. In any such circumstance and others described below, the trading price of our securities could decline and you could lose part or all of your investment.

Risk Factors Summary

The following is a summary of the material risk factors that could adversely affect our business, financial condition, and results of operations:

- **Risks Relating to the Oil and Natural Gas Industry and Our Business**
  - Oil, natural gas and NGL prices fluctuate widely due to a number of factors that are beyond our control
  - Drilling for and producing oil and natural gas are high risk activities with many uncertainties
  - Market conditions or operational impediments may hinder our access to oil, natural gas and NGL markets or delay production
  - A financial downturn could negatively affect our business, results of operations, financial condition, cash flows and access to capital
  - Future drilling activities face substantial uncertainties
  - Certain of our undeveloped acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or we renew the leases
  - We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and our ability to offset the natural decline in our oil, natural gas and NGL reserves
  - Future commodity price declines may result in reductions of the asset carrying values of our oil and natural gas properties
  - Significant inaccuracies in our reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves
  - The loss of senior management or technical personnel or our inability to hire additional qualified personnel could adversely affect our operations
  - We are subject to litigation and adverse outcomes in such litigation could have a material effect on our financial condition
  - Changes affecting the availability of the London Inter-bank Offered Rate ("LIBOR") may have consequences for us that cannot yet be reasonably predicted
  - The present value of future net cash flows from our proved reserves are not the same as the current market value of our estimated oil, natural gas and NGL reserves
  - We will not know conclusively prior to drilling whether oil or natural gas will be present in sufficient quantities to be economically producible
  - Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather
  - Capital market volatility could adversely affect our ability to obtain capital, cause us to incur additional financing expense or affect the value of certain assets
  - Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them
  - All of our operations are located in the Mid-Continent region, making us vulnerable to risks associated with operating in a limited number of major geographic areas
  - Oil and natural gas wells are subject to operational hazards that can cause substantial losses for which we may not be adequately insured
  - Shortages or increases in costs of equipment, services and qualified personnel could adversely affect our ability to execute our development plans
  - Intense competition in the oil and natural gas industry may adversely affect our ability to succeed
  - Seismic data may not accurately identify the presence of oil and natural gas, and the use of such technology requires greater predrilling expenditures
  - Inflation may increase costs which can adversely impact cash flows and reserves value
  - Disruptions or delays at our third-party service providers could adversely impact our operations
  - Complex laws and regulations could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities
  - Should we fail to comply with all applicable statutes, rules, regulations and orders of the FERC, the CFTC, the FTC or other regulators, we could be subject to substantial penalties and fines

- Our operations are subject to environmental and occupational safety and health laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations
- Legislative or regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and adversely affect our production
- Legislative or regulatory initiatives relating to seismic activity could limit our ability to produce oil and natural gas economically
- Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce
- Our failure to maintain an adequate system of internal control over financial reporting could adversely affect our ability to accurately report our results
- Our derivative activities could result in financial losses and are subject to new derivatives legislation and regulation, which could adversely affect our ability to hedge risks associated with our business
- Cyber-attacks or other failures in telecommunications or IT systems could result in information theft, data corruption and significant disruption of our business operations
- Repercussions from terrorist activities or armed conflict could harm our business
- Conservation measures and technological advances could reduce demand for oil and natural gas
- Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business

- **Risks Relating to our NOLs**
  - Our ability to use our NOLs may be limited, and our Tax Benefits Preservation Plan may not prevent an ownership change resulting in loss of the Company's NOLs

- **Risks Relating to our Common Stock**
  - We have adopted a Tax Benefits Preservation Plan, which may discourage a corporate takeover
  - Anti-takeover provisions in our charter documents may make it more difficult to acquire us, even though such acquisitions may be beneficial to our stockholders

For a more complete discussion of the material risk factors relevant to us, see below.

- **Risks Relating to the Oil and Natural Gas Industry and Our Business**

Oil, natural gas and NGL prices fluctuate widely due to a number of factors that are beyond our control. Declines in oil, natural gas or NGL prices significantly affect our financial condition and results of operations.

Our revenues, profitability and cash flow are highly dependent upon the prices we realize from the sale of oil, natural gas and NGLs. Historically, the markets for these commodities are very volatile. Prices for oil, natural gas and NGLs can move quickly and fluctuate widely in response to a variety of factors that are beyond our control. These factors include, among others:

- changes in regional, domestic and foreign supply of, and demand for, oil, natural gas and NGLs, as well as perceptions of supply of, and demand for, oil, natural gas and NGLs generally;
- the price and quantity of foreign imports;
- the amount of exports from the U.S.;
- U.S. and worldwide political and economic conditions, including armed conflict and related sanctions;
- the level of global and U.S. inventories and reserves;
- weather conditions and seasonal trends;
- anticipated future prices of oil, natural gas and NGLs, alternative fuels and other commodities;
- technological advances affecting energy consumption and energy supply;
- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- natural disasters and other extraordinary events;
- domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures;
- the price and availability of alternative fuels and energy sources;

- the strength or weakness of the U.S. dollar to other currencies;
- inflation and ability to acquire critical material, equipment or services in a timely or cost effective manner; and
- availability of capital or level of hedging across the energy industry in the U.S. and internationally.

These factors and the volatility of the energy markets, which we expect will continue, make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For oil, from January 2018 through December 2022, the NYMEX West Texas Intermediate ("WTI") settled price fluctuated between a high of $123.64 per Bbl and a low of $(36.98) per Bbl. For natural gas, from January 2018 through December 2022, the month-end NYMEX Henry Hub settled price fluctuated between a high of $24.74 per Mcf and a low of $1.38 per Mcf. In addition, the market price of natural gas is generally higher in the winter months than during other months of the year due to increased demand for natural gas for heating purposes during the winter season. For NGLs, prices exhibited similar volatility from January 2018 through December 2022.

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

Drilling for oil and natural gas can be unprofitable if dry wells are drilled and if productive wells do not produce sufficient revenues to return a profit. Furthermore, even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. Decisions to develop properties depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The estimated cost of drilling, completing and operating wells is uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of various factors, including among others the following:

- reductions in oil, natural gas and NGL prices;
- delays imposed by or resulting from compliance with regulatory requirements including permitting;
- unusual or unexpected geological formations and miscalculations;
- shortages of or delays in obtaining equipment and qualified personnel;
- shortages of or delays in obtaining water and sand for hydraulic fracturing operations;
- equipment malfunctions, failures or accidents;
- lack of available gathering or midstream facilities or delays in construction of gathering or midstream facilities;
- lack of available capacity on interconnecting transmission pipelines;
- lack of adequate electrical infrastructure and water disposal capacity;
- unexpected operational events and drilling conditions;
- pipe or cement failures and casing collapses;
- pressures, fires, blowouts and explosions;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil, natural gas, brine, water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil spills and natural gas leaks, pipeline or tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- high costs, shortages or delivery delays of equipment, labor or other services, or water used in hydraulic fracturing;
- compliance with environmental and other governmental requirements;

- adverse weather conditions such as extreme cold, fires caused by extreme heat or lack of rain, and severe storms, tornadoes or hurricanes;
- oil and natural gas property title problems;
- market and midstream limitations for oil, natural gas and NGLs;
- unexpected subsurface conditions;
- lack of qualified labor;
- lack of hydrocarbon content; and
- low pressure, depletion from existing wells, parent / child effect, or other conditions that may reduce ultimate recovery of reserves.

Certain of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, environmental contamination or loss of wells and regulatory fines or penalties.

Market conditions or operational impediments may hinder our access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs.

Market conditions or a lack of satisfactory oil and natural gas transportation arrangements may hinder our access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs. The availability of a ready market for our oil, natural gas and NGL production depends on a number of factors, including the demand for and supply of oil, natural gas and NGLs and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and treating facilities for oil, natural gas and NGLs as well as gathering systems, treating facilities and disposal wells for water produced alongside the hydrocarbons. Our failure to obtain such services on acceptable terms in the future or to expand our midstream assets could have a material adverse effect on our business. We may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering system capacity, treating facilities or disposal wells may be limited or unavailable. We would be unable to realize revenue from any shut-in wells until production arrangements were made to deliver the production to market.

A financial downturn could negatively affect our business, results of operations, financial condition, cash flows and access to capital.

Actual or anticipated declines in domestic or foreign economic growth rates, regional or worldwide increases in tariffs or other trade restrictions, turmoil affecting the U.S. or global financial system and markets and a severe economic contraction either regionally or worldwide, resulting from a variety of factors including COVID-19, could materially affect our business and financial condition and impact our ability to finance operations or acquisitions by worsening the actual or anticipated future drop in worldwide commodity demand, negatively impacting the price we receive for our oil and natural gas production. Negative economic conditions could also adversely affect the collectability of our trade receivables or performance by our vendors and suppliers. All of the foregoing may adversely affect our business, financial condition, results of operations, and cash flows.

Future drilling activities face substantial uncertainties.

Our ability to drill and develop wells on our existing acreage depends on a number of uncertainties, including oil, natural gas and NGL prices, availability of qualified labor, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering and midstream system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if certain locations will ever be drilled or if we will be able to produce natural gas or oil from any of our potential locations.

Certain of our undeveloped acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or we renew the leases.

A portion of our acreage is undeveloped and subject to leases that will expire unless we exercise our contractual rights to extend or renew the terms of the leases or we establish production in paying quantities prior to expiration. Our ability to establish production in paying quantities on or renew our expiring leases is based on various factors that may be beyond our control, such as the availability and cost of capital, equipment, services and personnel; the ability to renew leases on commercially favorable terms or at all; market prices of oil and natural gas; drilling costs and results; and production costs, among other factors. Renewing such leases may cause us to incur additional costs. If we are unable to establish production in paying quantities on or renew such leases, those leases will expire, and we will lose our right to participate in the development of the subject leases, which may adversely affect our results of operations. As of December 31, 2022, we hold approximately 365,000 total net acres (including developed and undeveloped net acres), of which 27,011 net aces is undeveloped. Of our undeveloped acreage, less than 5% are subject to expiration at the end of their primary terms. For additional information on our developed and undeveloped acreage please see the section "Item 1. Business—Developed and Undeveloped Acreage."

Our development operations or ability to acquire oil and gas properties and reserves require substantial capital. Outside of our cash assets, we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss in our ability to offset the natural decline in our oil, natural gas and NGL reserves, which would adversely affect our business, financial condition and results of operations.

The oil and natural gas industry is capital intensive. Our future oil, natural gas and NGL reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current estimated proved reserves and finding or acquiring additional economically recoverable reserves. We make substantial capital expenditures in our business and operations for the acquisition, development and production of oil, natural gas and NGL reserves. Historically, we have financed capital expenditures primarily with cash generated by operations, credit facility borrowings and proceeds from asset sales. In particular, cash flow from operations were $164.7 million and $110.3 million for the years ended December 31, 2022 and 2021, respectively.

The capital markets that we have historically accessed have recently been and may continue to be constrained to such an extent that debt or equity capital raises are practically unfeasible. If the debt and equity capital markets are not accessible, we may be unable to implement our development plans or otherwise carry out our business strategy as expected. Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which oil, natural gas and NGLs are sold;
- our proved reserves;
- the level of oil, natural gas and NGLs we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves; and
- our capital and operating costs.

Further, we may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which could adversely affect our business, financial condition, access to capital and results of operations.

Disruptions in the global financial and capital markets could also adversely affect our ability to obtain debt or equity financing on favorable terms, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to development of prospects, which in turn could lead to a possible loss of properties and a decline in our oil, natural gas and NGL reserves.

Future price declines may result in reductions of the asset carrying values of our oil and natural gas properties.

We utilize the full cost method of accounting for costs related to our oil and natural gas properties. Under this accounting method, all costs for both productive and nonproductive properties are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, the amount of these costs that can be carried as capitalized assets is subject to a ceiling, which limits such pooled costs to the aggregate of the present value of future net revenues of proved oil, natural gas and NGL reserves attributable to proved properties, discounted at 10%, plus the cost of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the SEC prices, adjusted for the impact of derivatives accounted for as cash flow hedges, if any. The Company did not recognize any full cost ceiling impairment charges for the years ended December 31, 2022 or 2021. Cumulative full cost ceiling impairment from the Emergence Date through December 31, 2022 totaled $947.1 million. If oil, natural gas and NGL prices decline further in the near term, and without other mitigating circumstances, we may experience additional losses of future net revenues, including losses attributable to quantities that cannot be economically produced at lower prices, which would likely cause us to record additional write-downs of capitalized costs of oil and natural gas properties and non-cash charges against future earnings. The amount of such future write-downs and non-cash charges could be substantial.

Our estimated reserves are based on many assumptions that may turn out to be different. Any significant inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves. Our current estimates of reserves could change, potentially in material amounts, in the future.

The process of estimating oil, natural gas and NGL reserves is complex and inherently imprecise, requiring interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as historic oil and natural gas prices, drilling and operating expenses, capital expenditures, the assumed effect of governmental regulation and availability of funds for development expenditures. Inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. See "Business—Primary Business Operations" in Item 1 of this report for information about our oil, natural gas and NGL reserves.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves will vary and could vary significantly from our estimates shown in this report, which in turn could have a negative effect on the value of our assets. In addition, from time to time in the future, we will adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development, changes in oil, natural gas and NGL prices and other factors, many of which are beyond our control.

The ability to attract and retain key personnel is critical to the success of our business and the loss of senior management or technical personnel or our inability to hire additional qualified personnel could adversely affect our operations.

The success of our business depends on key personnel, including members of senior management and technical personnel. The ability to attract and retain these key personnel may be difficult in light of the uncertainties currently facing the business and changes we may make to the organizational structure to adjust to changing circumstances. The market for qualified personnel has historically been, and we expect that it will continue to be, intensely competitive. We cannot assure that we will be successful in attracting or retaining such personnel. We may need to enter into retention or other arrangements that could be costly to maintain. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them in a timely manner and we could experience significant declines in productivity or effectiveness.

We are subject to litigation and adverse outcomes in such litigation could have a material effect on our financial condition.

We are, and from time to time may become, subject to litigation and various legal proceedings, including stockholder derivative suits, class action lawsuits and other matters, that involve claims for substantial amounts of money or for other relief or that might necessitate changes to our business or operations. Refer to Item 3. "Legal Proceedings" for additional information.

Changes affecting the availability of the London Inter-bank Offered Rate ("LIBOR") may have consequences for us that cannot yet be reasonably predicted.

The LIBOR benchmark has been the subject of national, international and other regulatory guidance and proposals to reform. In July 2017, the United Kingdom Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. In March 2021, ICE Benchmark Administration, the administrator for LIBOR, ceased publishing United States Dollar LIBOR ("USD LIBOR") for one week and two-month tenors after December 31, 2021, and confirmed its intention to cease all remaining USD LIBOR tenors after June 30, 2023. Concurrently, the United Kingdom Financial Conduct Authority announced the cessation or loss of representativeness of the USD LIBOR tenors from those dates. The Alternative Reference Rates Committee, a group of market participants convened by the United States Federal Reserve Board and the Federal Reserve Bank of New York, has recommended the Secured Overnight Financing Rate ("SOFR"), a rate calculated based on repurchase agreements backed by United States Treasury securities, as its recommended alternative benchmark rate to replace USD LIBOR. At this time, it is not known whether or when SOFR or other alternative reference rates will attain market traction as replacements for LIBOR. These reforms may cause LIBOR to perform differently than it has in the past, and LIBOR will cease to exist after June 30, 2023. After the cessation of LIBOR, alternative benchmark rates will replace LIBOR and could affect our debt securities, debt payments and receipts. At this time, it is not possible to predict the effect of any changes to LIBOR, any phase out of LIBOR or any establishment of alternative benchmark rates. Any new benchmark rate will likely not replicate LIBOR exactly, which could impact our contracts that terminate after June 30, 2023. There is uncertainty about how applicable law and the courts will address the replacement of LIBOR with alternative rates on variable rate retail loan contracts and other contracts that do not include alternative rate fallback provisions. In addition, any changes to benchmark rates may have an uncertain impact on our cost of funds and our access to the capital markets, which could impact our results of operations and cash flows. Uncertainty as to the nature of such potential changes may also adversely affect the trading market for our securities.The full effects of the transition away from LIBOR remain uncertain.

The present value of future net cash flows from our proved reserves calculated in accordance with SEC guidelines are not the same as the current market value of our estimated oil, natural gas and NGL reserves.

We base the estimated discounted future net cash flows from our proved reserves on 12-month average index prices and costs, as is required by SEC rules and regulations. Actual future net cash flows from our oil and natural gas properties will be affected by actual prices we receive for oil, natural gas and NGLs, as well as other factors such as:

- the actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil, natural gas and NGLs; and
- changes in governmental regulation or taxation.

The timing of both our production and incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, we use a 10% discount factor when calculating discounted future net cash flows, which 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.

We will not know conclusively prior to drilling whether oil or natural gas will be present in sufficient quantities to be economically producible.

The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive or may suffer from declining production faster than anticipated. The use of seismic data and other technologies and the study of producing fields in the same area do not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable.

Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather.

Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather. Repercussions of natural disasters or severe weather conditions may include:

- evacuation of personnel and curtailment of operations;
- damage to drilling rigs or other facilities, resulting in suspension of operations;
- inability to deliver materials to worksites; and
- damage to, or shutting in of, pipelines and other transportation facilities.

In addition, our hydraulic fracturing operations require significant quantities of water. Regions in which we operate may experience drought conditions from time to time. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs.

Our business could be affected by macroeconomic risks.

Our operations and performance depend significantly on global and regional economic conditions. Macroeconomic conditions, including inflation, slower growth or recession, changes to fiscal and monetary policy, tighter credit, higher interest rates, high unemployment and currency fluctuations can materially adversely affect demand for our products and services. In addition, confidence and spending can be materially adversely affected in response to financial market volatility, negative financial news, declines in income or asset values, energy shortages and cost increases, labor costs and other economic factors. An adverse impact on demand for our products and services, uncertainty about, or a decline in, global or regional economic conditions can have a significant impact on our operations. Potential effects include financial instability; inability to obtain credit to finance operations and purchases of our products. We cannot predict the timing or scale of these various macroeconomic conditions, but they could have a material adverse affect on our business, results of operations and financial condition.

The capital markets could be volatile, and such volatility could adversely affect our ability to obtain capital, cause us to incur additional financing expense or affect the value of certain assets.

In some cases, financial markets produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial and/or operating strength. Volatility in the capital markets can significantly increase the cost of raising money in the debt and equity capital markets. Generally, future market volatility and risk of persistent weakness in commodity prices may adversely affect our ability to access capital and credit markets or to obtain funds at low interest rates or on other advantageous terms. These factors may adversely affect our business, results of operations or liquidity.

Adverse credit and capital market conditions may require us to reduce the carrying value of assets associated with any derivative contracts to account for non-performance by, or increased credit risk from, counterparties to those contracts. If financial institutions that extended credit commitments to us are adversely affected by volatile conditions of the U.S. and international capital markets, they may become unable to fund borrowings under their credit commitments to us, which could have a material adverse effect on our financial condition and ability to borrow funds, if needed, for working capital, capital expenditures and other corporate purposes.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

Our initial technical reviews of properties we acquire are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on our results of operations and financial condition.

All of our operations are located in the Mid-Continent region, making us vulnerable to risks associated with operating in a limited number of major geographic areas.

With the divestment of our North Park Basin assets in February 2021, all of our production and reserves are located in the Mid-Continent region. This concentration could disproportionately expose us to operational and regulatory risk in this area. This relative lack of diversification in location of our key operations could expose us to adverse developments in the Mid-Continent or the oil and natural gas markets, including, for example, transportation or treatment capacity constraints, curtailment of production due to weather, electrical outages, treatment plant closures for scheduled maintenance, changes in the regulatory environment or other factors. These factors could have a significantly greater impact on our financial condition, results of operations and cash flows than if our properties were more diversified.

Oil and natural gas wells are subject to operational hazards that can cause substantial losses for which we may not be adequately insured.

There are a variety of operating risks inherent in oil, natural gas and NGL production and associated activities, such as fires, leaks, explosions, mechanical problems, major equipment failures, blowouts, uncontrollable flow of oil, natural gas and NGLs, water or drilling fluids, casing collapses, abnormally pressurized formations and natural disasters. The occurrence of any of these or similar accidents that temporarily or permanently halt the production and sale of oil, natural gas and NGLs at any of our properties could have a material adverse impact on our business activities, financial condition and results of operations.

Additionally, if any of such risks or similar accidents occur, we could incur substantial losses as a result of injury or loss of life, severe damage or destruction of property, natural resources and equipment, regulatory investigation and penalties and environmental damage and clean-up responsibility. If we experience any of these problems, our ability to conduct operations could be adversely affected. While we maintain insurance coverage that we deem appropriate for these risks, our operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance.

Shortages or increases in costs of equipment, services and qualified personnel could adversely affect our ability to execute our development plans on a timely basis and within our budget.

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Additionally, higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly affect our ability to execute our development plans as projected.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with many companies that have greater financial and other resources than we do. Many of these companies not only explore for and produce oil and natural gas, but also conduct refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration and development activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the economic results of drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are present in those structures. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals. Our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve as a result of using 2-D and 3-D seismic data.

The use of 2-D and 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. In addition, we may often gather 2-D and 3-D seismic data over large areas in order to help us delineate those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in such location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 2-D and 3-D seismic data without having an opportunity to benefit from those expenditures.

Inflation may increase costs which can adversely impact cash flows and reserves value

Inflation can adversely affect us by increasing costs of critical materials, equipment, labor, and other services. In addition, inflation is often accompanied by higher interest rates. Continued inflationary pressures could impact our cash flows, reserves value, and our profitability. Additionally, inflation can impact the economics of future projects which could result in reduced investment activity and our ability to offset natural declines.

As we outsource functions, we become more dependent on the entities performing those functions. Disruptions or delays at our third-party service providers could adversely impact our operations.

As part of our long-term profitable growth strategy, we are continually looking for opportunities to provide essential business services in a more cost-effective manner. In some cases, this requires the outsourcing of functions or parts of functions that can be performed more effectively by external service providers. For example, we currently outsource a significant portion of our accounting functions to third-party service providers. While we believe we conduct appropriate diligence before entering into agreements with any outsourcing entity, the failure of one or more of such entities to meet our performance standards and expectations, including with respect to providing services on a timely basis or providing services at the prices we expect, may have an adverse effect on our results of operations or financial condition. For example, our outsourcing entities and other third-party service providers may experience difficulties, disruptions, delays, or failures in their ability to deliver services to us as a result of a variety of factors including COVID-19. We could face increased costs or disruption associated with finding replacement vendors or hiring new employees in order to return these services in-house, which may have a significant impact on our cost of operations. Any failures of these vendors to properly deliver their services could similarly have a material effect on our business. We may outsource other functions in the future, which would increase our reliance on third parties.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our oil and natural gas development, production, transportation and treatment operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these laws and regulations. As a result of recent incidents involving the release of oil and natural gas and fluids as a result of drilling activities in the United States, there have been a variety of regulatory initiatives at the federal and state levels to restrict oil and natural gas drilling operations in certain locations. Any increased regulation or suspension of oil and natural gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on our business, financial condition and results of operations. We must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent we are a shipper on interstate pipelines, we must comply with the FERC-approved tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Laws and regulations governing oil and natural gas operations may also affect production levels. We are required to comply with federal and state laws and regulations governing conservation matters, including provisions related to the unitization or pooling of our oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; and the plugging and abandonment of wells. These and other laws and regulations can limit the amount of oil and natural gas we can produce from our wells, limit the number of wells we can drill, or limit the locations at which we can conduct drilling operations.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may increase capital costs for us and third-party downstream oil and natural gas transporters. These and other potential regulations could increase our operating costs, reduce our liquidity, delay our operations, increase direct and third-party post production costs or otherwise alter the way we conduct our business, which could have a material adverse effect on our financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid for transportation on downstream interstate pipelines.

Should we fail to comply with all applicable statutes, rules, regulations and orders of the FERC, the CFTC, the FTC or other regulators, we could be subject to substantial penalties and fines.

Under the EPAct 2005 and implementing regulations, the FERC prohibits market manipulation in connection with the purchase or sale of natural gas. The CFTC has similar authority under the Commodity Exchange Act and regulations it has promulgated thereunder with respect to certain segments of the physical and futures energy commodities market including oil and natural gas. The FTC also prohibits manipulative or fraudulent conduct in the wholesale petroleum market with respect to sales of commodities, including crude oil, condensate and natural gas liquids. Other regulatory entities have jurisdiction over our industry and operations. These agencies have substantial enforcement authority, including the ability to impose penalties for current violations in excess of $1 million per day for each violation. The FERC has also imposed requirements related to reporting of natural gas sales volumes that may impact the formation of prices indices. Additional rules and legislation pertaining to these and other matters may be considered or adopted from time to time. Our failure to comply with these or other laws and regulations administered by these agencies could subject us to criminal and civil penalties, as described in Item 1. "Business— Other Regulation of the Oil and Natural Gas Industry."

Our operations are subject to environmental and occupational safety and health laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations or result in significant costs and liabilities.

Our oil and natural gas operations are subject to stringent and complex federal, state, tribal, regional and local laws and regulations governing worker safety and health, the discharge and disposal of substances into the environment or otherwise relating to environmental protection. Failure to comply with these laws and regulations may result in litigation; the assessment of sanctions, including administrative, civil or criminal penalties; the imposition of investigatory, remedial or corrective action obligations; the occurrence of delays or restrictions in permitting or performance of projects; and the issuance of orders and injunctions limiting or preventing some or all of our operations in affected areas.

Under certain environmental laws and regulations, we could be subject to strict, and/or joint and several liability for the investigation, removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled or facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, to seek damages for contamination, for personal injury, natural resources damage or property damage.

Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management, or completion activities or waste handling, storage, transport, remediation or disposal, emission or discharge requirements could require significant expenditures by us to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and natural gas production. We routinely have utilized hydraulic fracturing techniques in the majority of our drilling and completion programs. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued CAA final regulations in 2012 and additional CAA regulations in June 2016 governing performance standards for the oil and natural gas industry; and in June 2016 issued final effluent limitations guidelines under the CWA that waste-water from shale natural gas extraction operations must meet before discharging to a publicly-owned treatment plant. The EPA also issued an Advance Notice of Proposed Rulemaking under TSCA in 2014 regarding reporting of the chemical substances and mixtures used in hydraulic fracturing, but, to date, has taken no further action. Separately, the BLM published a final rule in March 2015 that establishes more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, the U.S. District Court of Wyoming struck down this rule in June 2016, and after various appeals and a presidential executive order directing it to review rules related to the energy industry, the BLM published a final rule rescinding the 2015 rule in December 2017.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears uncertain. In addition, certain states, including Oklahoma, have adopted regulations that could impose new or more stringent permitting, disclosure, and well-construction requirements on hydraulic fracturing operations. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted at the local, state or federal level, fracturing activities with respect to our properties could become subject to additional permit requirements, reporting requirements or operational restrictions, which may result in permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas or NGLs that are ultimately produced in commercial quantities from our properties.

Legislation or regulatory initiatives intended to address seismic activity are restricting and could restrict our ability to dispose of saltwater produced alongside our hydrocarbons, which could limit our ability to produce oil and natural gas economically and have a material adverse effect on our business.

Large volumes of saltwater produced alongside our oil, natural gas and NGLs in connection with drilling and production operations are disposed of pursuant to permits issued by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt water disposal activities occur or are proposed to be performed. The adoption of any new laws, regulations, or directives that restrict our ability to dispose of saltwater generated by production and development activities, whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring us to shut down disposal wells, which could negatively affect the economic lives of our properties.

Refer to "—Environmental Regulations— Subsurface Injections" included in Item 1 of this report for additional discussion of the current and potential impacts of legislation or regulatory initiatives related to seismic activity on our operations.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

The EPA previously published its findings that emissions of GHGs present a danger to public health and the environment because such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted various rules to address GHG emissions under existing provisions of the CAA. For example, the EPA has adopted rules requiring the reporting of GHG emissions from various oil and natural gas operations on an annual basis, which includes certain of our operations. In addition, in June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, including implementation of an LDAR program to minimize methane emissions, under the CAA's New Source Performance Standards Quad Oa. However, the EPA has taken several steps to delay implementation of the Quad Oa standards. The agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and in October 2018, the EPA proposed revisions to Quad Oa, such as changes to the frequency for monitoring fugitive emissions at well sites and changes to requirements that a professional engineer certify when meeting certain Quad Oa requirements is technically infeasible. In September 2020, the EPA finalized amendments to Quad Oa that rescind requirements for the transmission and storage segment of the oil and natural gas industry and rescind methane-specific limits that apply to the industry's production and processing segments, among other things. On June 30, 2021, Congress issued a joint resolution pursuant to the Congressional Review Act disapproving the September 2020 rule, and on November 15, 2021, EPA issued a proposed rule to revise the Quad Oa regulations that, if finalized, would require methane emissions reductions and implementation of a fugitive emissions monitoring and repair program. On November 8, 2022, EPA issued a supplemental notice of proposed rulemaking that would impose standards for certain sources that were not addressed in the November 2021 proposal, revise the previously proposed emissions standards, and establish a "super emitter response program" allowing local regulatory agencies and EPA-certified third parties to issue notices to owners and operators of regulated facilities when they detect a so-called "super-emitting event." EPA is expected to finalize the rulemaking in late 2023. It is possible that these rules will continue to require oil and gas operators to expend material sums.

In addition, in November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands that are substantially similar to the EPA Quad Oa requirements. However, on December 8, 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule to revise or rescind certain provisions of the 2016 rule. On July 21, 2020, a Wyoming federal court vacated almost all of the 2016 rule, including all provisions relating to the loss of gas through venting, flaring, and leaks, and on July 15, 2020, a California federal court vacated the 2018 rule. On November 28, 2022, BLM announced a new proposed rule regulating emissions of methane in connection with the production of oil and gas on federal and Tribal lands. If finalized, the proposed rule would require various technology upgrades, impose limits related to flaring, and require LDAR plans. The final rule is expected to be announced later this year. While, as a result of these developments, future implementation of the EPA and BLM methane rules is uncertain, given the long-term trend towards increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility. We have the necessary equipment (pollution control equipment and optical gas imaging equipment for LDAR inspections) and personnel trained to assist with inspection and reporting requirements to maintain compliance with these rules.

In addition, there are a number of state and regional efforts that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. On an international level, the United States was one of almost 200 nations that agreed in December 2015 to the Paris Agreement. However, the Paris Agreement did not impose any binding obligations on the United States. In June 2017, the United States announced it would withdraw from the Paris Agreement, which became effective November 4, 2020. The United States has rejoined the Paris Agreement as of February 19, 2021.

The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and our operations could require us to incur additional costs to monitor, report and potentially reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for development and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on our assets and operations, and potentially subject us to greater regulation.

Our failure to maintain an adequate system of internal control over financial reporting, could adversely affect our ability to accurately report our results.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our 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 in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in our internal control over financial reporting that results in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are necessary for us to provide reliable financial reports and deter and detect any material fraud. If we cannot provide reliable financial reports or prevent material fraud, our reputation and operating results would be harmed. We maintained effective internal control over financial reporting as of December 31, 2022, as further described in Part II "Item 9A—Controls and Procedures" and "Management's Report on Internal Control over Financial Reporting." Our efforts to develop and maintain our internal controls and to remediate any material weaknesses in our controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation, including those related to acquired businesses, or other effective improvement of our internal controls could harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

Our derivative activities could result in financial losses and are subject to new derivatives legislation and regulation, which could adversely affect our ability to hedge risks associated with our business.

We have entered and may enter into financial derivative instruments with respect to a portion of our production to manage our exposure to oil, gas, and NGL price volatility. To the extent that we engage in price risk management activities to protect the Company from commodity price declines, we would be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the contract counterparties fail to perform under the contracts. Further, to date, we have not designated and do not currently plan to designate any of our derivative contracts as hedges for accounting purposes and, as a result, record all derivative contracts on our balance sheet at fair value with changes in fair value recognized in current period earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative contracts.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") created a new regulatory framework for oversight of derivatives transactions by the CFTC and the SEC. Among other things, the Dodd-Frank Act subjects certain swap participants to new capital, margin and business conduct standards. In addition, the Dodd-Frank Act contemplates that where appropriate in light of outstanding exposures, trading liquidity and other factors, swaps (broadly defined to include most hedging instruments other than futures) will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility, unless the "end-user" exception from clearing applies. The Dodd-Frank Act also established a new Energy and Environmental Markets Advisory Committee to make recommendations to the CFTC regarding matters of concern to exchanges, firms, end users and regulators with respect to energy and environmental markets and also expands the CFTC's power to impose position limits on specific categories of swaps (excluding swaps entered into for *bona fide* hedging purposes).

There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. However, although we may qualify for exceptions, our derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the Dodd-Frank Act, which may increase our transaction costs or make it more difficult for us to enter into hedging transactions on favorable terms.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

Cyber-attacks or other failures in telecommunications or IT systems could result in information theft, data corruption and significant disruption of our business operations.

In recent years, we have increasingly relied on information technology systems and networks in connection with our business activities, including certain of our acquisition, development and production activities. We rely on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to, among other things, estimate quantities of oil and natural gas reserves, analyze seismic and drilling information, process and record financial and operating data and communicate with employees and third parties. As dependence on digital technologies has increased, cyber incidents, including deliberate attacks and attempts to gain unauthorized access to computer systems and networks, have increased in frequency and sophistication. These threats pose a risk to the security of our systems and networks, the confidentiality, availability and integrity of our data and the physical security of our employees and assets. We have experienced, and expect to continue to confront, attempts from hackers and other third parties to gain unauthorized access to our information technology systems and networks. Although prior cyber-attacks have not had a material adverse impact on our operations or financial performance, there can be no assurance that we will be successful in preventing cyber-attacks or successfully mitigating their effect. Any cyber-attack could have a material adverse effect on our reputation, competitive position, business, financial condition and results of operations. Cyber-attacks or security breaches also could result in litigation and legal risks, including regulatory actions by state, federal, and non-US governmental authorities, as well as significant additional expense to implement further data protection measures.

In addition to the risks presented to our systems and networks, cyber-attacks affecting oil and natural gas distribution systems maintained by third parties, or the networks and infrastructure on which they rely, could delay or prevent delivery of our production to markets. A cyber-attack of this nature would be outside our control, but could have a material, adverse effect on our business, financial condition and results of operations.

We have programs, processes and technologies in place to attempt to prevent, detect, contain, respond to and mitigate security-related threats and potential incidents, as well as internal accounting controls to prevent unauthorized or fraudulent payments by ensuring that transactions are executed only with management authorization. We undertake ongoing improvements to our systems, connected devices and information-sharing products in order to minimize vulnerabilities, in accordance with industry and regulatory standards; however, because the techniques used to obtain unauthorized access change frequently and can be difficult to detect, anticipating, identifying or preventing these intrusions or mitigating them if and when they occur is challenging and makes us more vulnerable to cyber-attacks than other companies not similarly situated.

If our security measures are circumvented, proprietary information may be misappropriated, our operations may be disrupted, and our computers or those of our customers or other third parties may be damaged. Compromises of our security may result in an interruption of operations, violation of applicable privacy and other laws, significant legal and financial exposure, damage to our reputation, and a loss of investor confidence in our security measures. Additional impacts from cyber-attacks could include remediation costs, such as liability for stolen assets or information, repairs of system damage, and incentives to our business partners; increased cybersecurity protection costs, which may include the costs of making organizational changes, deploying additional personnel and security technologies, training employees, and engaging third-party experts and consultants; lost revenue resulting from the unauthorized use of proprietary information or the failure to retain or attract business partners following an attack; increased insurance premiums; and damage to the company's competitiveness, stock price, and long-term shareholder value.

Repercussions from terrorist activities or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts or other armed conflict involving the United States or its interests abroad may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If events of this nature occur and persist, the attendant political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on prevailing oil and natural gas prices and causing a reduction in our revenues. Oil and natural gas production facilities, transportation systems and storage facilities could be direct targets of terrorist attacks, and/or operations could be adversely impacted if infrastructure integral to our operations is destroyed by such attacks. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

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

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

Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.

We face risks related to epidemics, outbreaks or other public health events that are outside of our control, and could significantly disrupt our operations and adversely affect our financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis, such as COVID-19, may cause disruptions to our business and operational plans, which may include (i) shortages of employees, (ii) unavailability of contractors or subcontractors, (iii) interruption of supplies from third parties upon which we rely, (iv) recommendations of, or restrictions imposed by government and health authorities, including quarantines, to address an outbreak and (v) restrictions that we and our contractors, subcontractors and our customers impose, including facility shutdowns, to ensure the safety of employees. The effects of COVID-19 and other infectious diseases and concerns regarding their global spread could negatively impact the domestic and international demand for crude oil, natural gas and NGL, which could contribute to price volatility, impact the price we receive for crude oil, natural gas and NGL and materially and adversely affect the demand for and marketability of our production. The potential impact from COVID-19, both now and in the future, is difficult to predict, and the extent to which it may negatively affect our operating results or the duration of any potential business disruption is uncertain.

Risks Relating to our NOLs

Our ability to use our NOLs may be limited. We have adopted a Tax Benefits Preservation Plan that is designed to protect our NOLs but there is no assurance it will prevent an ownership change resulting in loss of the Company's NOLs.

As of December 31, 2022, we had U.S. federal NOLs of $1.6 billion, net of NOLs expected to expire unused due to the 2016 IRC Section 382 limitation, approximately half of which will expire between 2025 and 2037, if not limited by additional triggering events prior to such time. Under the provisions of the Internal Revenue Code of 1986, as amended ("IRC"), changes in our ownership, in certain circumstances, will limit the amount of U.S. federal NOLs that can be utilized annually in the future to offset taxable income. In particular, Section 382 of the IRC imposes limitations on a company's ability to use NOLs upon certain changes in such ownership. Generally, an "ownership change" occurs if the percentage of the Company's stock owned by one or more of its "five-percent shareholders" (as such term is defined in Section 382 of the IRC) increases by more than 50 percentage points over the lowest percentage of stock owned by such stockholder or stockholders at any time over a three-year period. Calculations pursuant to Section 382 of the IRC can be very complicated and no assurance can be given that upon further analysis, our ability to take advantage of our NOLs may be limited to a greater extent than we currently anticipate. We may experience ownership changes in the future as a result of subsequent shifts in our stock ownership that we cannot predict or control that could result in further limitations being placed on our ability to utilize our federal NOLs. If we are limited in our ability to use our NOLs in future years in which we have taxable income, we will pay more taxes than if we were able to utilize our NOLs fully.

On July 1, 2020, our Board of Directors approved, and the Company adopted, as amended on March 16, 2021 a Tax Benefits Preservation Plan in order to protect shareholder value against a possible limitation on the Company's ability to use its tax NOLs and certain other tax benefits to reduce potential future U.S. federal income tax obligations. The Tax Benefits Preservation Plan was approved at the 2021 annual meeting of stockholders on May 25, 2021. The Tax Benefits Preservation Plan is designed to reduce the likelihood of an "ownership change" as defined under Section 382 of the IRC in order to protect our NOLs by deterring any person or group from acquiring beneficial ownership of 4.9% or more of the Company's securities. However, there is no assurance that the Tax Benefits Preservation Plan will prevent all transfers that could result in such an "ownership change."

Risks Relating to our Common Stock

We have adopted a Tax Benefits Preservation Plan, which may discourage a corporate takeover.

On July 1, 2020, our Board of Directors adopted a Tax Benefits Preservation Plan as amended on March 16, 2021 and declared a dividend distribution of one right for each outstanding share of our common stock to stockholders of record at the close of business on July 13, 2020. The Tax Benefits Preservation Plan was approved at the 2021 annual meeting of stockholders on May 25, 2021. Each share of our common stock issued thereafter will also include one right. Each right entitles its holder, under certain circumstances, to purchase from us one one-thousandth of a share of our Series A Junior Participating Preferred Stock at an exercise price of $5.00 per right, subject to adjustment.

The Board adopted the Tax Benefits Preservation Plan in an effort to protect stockholder value by attempting to protect against a possible limitation on our ability to use our NOLs. We may utilize these NOLs in certain circumstances to offset future United States taxable income and reduce our United States federal income tax liability. Because the Tax Benefits Preservation Plan could make it more expensive for a person to acquire a controlling interest in us, it could have the effect of delaying or preventing a change in control even if a change in control was in our stockholders' interest.

Anti-takeover provisions in our charter documents and under Delaware corporate law may make it more difficult to acquire us, even though such acquisitions may be beneficial to our stockholders.

In addition to our Tax Benefits Preservation Plan, provisions of our certificate of incorporation and bylaws, as well as provisions of Delaware corporate law, could make it more difficult for a third party to acquire us, even though such acquisitions may be beneficial to our stockholders. These anti-takeover provisions include:

- lack of a provision for cumulative voting in the election of directors;
- the ability of our Board to authorize the issuance of "blank check" preferred stock to increase the number of outstanding shares and thwart a takeover attempt;
- advance notice requirements for nominations for election to the Board of Directors or for proposing matters that can be acted upon by stockholders at stockholder meetings; and
- limitations on who may call a special meeting of stockholders.

The provisions described above, our Tax Benefits Preservation Plan and provisions of Delaware corporate law relating to business combinations with interested stockholders may discourage, delay or prevent a third party from acquiring us. These provisions may also discourage, delay or prevent a third party from acquiring a large portion of our securities, or initiating a tender offer, even if our stockholders might receive a premium for their shares in the acquisition over the then current market price.

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

None.

Item 2. ***Properties***

Information regarding the Company's properties is included in Item 1.

Item 3. ***Legal Proceedings***

See "Note 12—Commitments and Contingencies" to the accompanying consolidated financial statements in Item 8 of this report.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

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

Since October 4, 2016, the Company's common stock has been listed on the New York Stock Exchange ("NYSE") under the symbol "SD."

On March 8, 2023, there were 326 record holders of the Company's common stock, which does not reflect persons or entities that hold the common stock in nominee or "street" name through various brokerage firms and financial institutions.

Issuer Purchases of Equity Securities

None.

Item 6. [Reserved].

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

The following discussion and analysis is intended to help the reader understand our business, financial condition, results of operations, liquidity and capital resources. This discussion and analysis should be read in conjunction with other sections of this report, including: "Business" in Item 1 and "Financial Statements and Supplementary Data" in Item 8. Our discussion and analysis includes the following subjects:

- Overview;
- Consolidated Results of Operations;
- Liquidity and Capital Resources;
- Valuation Allowance; and
- Critical Accounting Policies and Estimates.

We have applied the Securities and Exchange Commission's adopted FAST Act Modernization and Simplification of Regulation S-K, which limits the discussion to the two most recent calendar years. This discussion and analysis deals with comparisons of material changes in the consolidated financial statements for years ended December 31, 2022 and 2021. For the comparison of the years ended December 31, 2021 and 2020, see "Management's Discussion and Analysis of Consolidated Results of Operations" in Part II, Item 7 of our 2021 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 10, 2022.

Overview

We are an independent oil and natural gas company with a principal focus on acquisition, development and production activities in the U.S. Mid-Continent. Prior to February 5, 2021, we held assets in the North Park Basin, which have been sold in their entirety.

Operational Activities

For the year ended December 31, 2022, there were eight operated wells drilled and six wells completed. There was no drilling activity on our operated acreage during the year ended December 31, 2021. However, we brought wells that were previously not producing on to production as part of our well reactivation program during the year ended December 31, 2021.

The chart below shows production by product for the years ended December 31, 2022 and 2021:

(1) For the year ended December 31, 2021, North Park Basin had 67 MBoe in oil production.

Total production for the Company in 2022 was composed of approximately 14.7% oil, 54.4% natural gas and 30.9% NGLs compared to 14.1% oil, 52.5% natural gas and 33.4% NGLs in 2021.

Mid-Continent total production for the years ended December 31, 2022 and 2021 was composed of the following:

	Year Ended December 31,	
	2022	**2021**
Oil	14.7 %	13.2 %
NGL	30.9 %	33.7 %
Natural gas	54.4 %	53.1 %
Total	100.0 %	100.0 %

Highlighted Events

- Consistent with our 2022 capital development program, we drilled eight wells and completed six wells during the year ended December 31, 2022.
- On October 5, 2022 the Company's Board of Directors appointed Ms. Nancy Dunlap to serve as a member of the Board. Ms. Dunlap also joined the Audit Committee.
- As part of our well reactivation program, we returned 50 wells to production for the year ended December 31, 2022.

Outlook

We will continue to focus on growing the cash value and generation capability of our asset base in a safe, responsible and efficient manner, while exercising prudent capital allocations to projects we believe provide high rates of returns in the current commodity price environment. These projects include (1) a continuation of our well reactivation program, (2) artificial lift conversions to more efficient and cost effective systems and (3) focused drilling in high-graded areas. We will continue to monitor forward-looking commodity prices, results, costs and other factors that could influence returns on investments, which will continue to shape our disciplined development decisions in 2023 and beyond. We will also continue to maintain optionality to execute on value accretive merger and acquisition opportunities that could bring synergies, leverage our core competencies, compliment our portfolio of assets, further utilize our NOLs or otherwise yield attractive returns for our shareholders.

Consolidated Results of Operations

The majority of our consolidated revenues and cash flow are generated from the production and sale of oil, natural gas and NGLs. Our revenues, profitability and future growth depend substantially on prevailing prices received for our production, the quantity of oil, natural gas and NGLs we produce, and our ability to find and economically develop and produce our reserves. Prices for oil, natural gas and NGLs fluctuate widely and are difficult to predict. To provide information on the general trend in pricing, the average annual NYMEX prices for oil and natural gas for recent years are presented in the table below:

	Year Ended December 31,	
	2022	2021
NYMEX WTI Oil (per Bbl)	$ 94.90	$ 68.18
NYMEX Henry Hub Natural gas (per Mcf)	$ 6.68	$ 4.04

In order to reduce our exposure to price fluctuations, from time to time we enter into commodity derivative contracts for a portion of our anticipated future oil, natural gas, and NGL production as discussed in Item 7A. "Quantitative and Qualitative Disclosures About Market Risk." During periods where the strike prices for our commodity derivative contracts are below market prices at the time of settlement, we may not fully benefit from increases in the market price of oil, natural gas and NGLs. Conversely, during periods of declining market prices of oil, natural gas and NGL, our commodity derivative contracts may partially offset declining revenues and cash flow to the extent strike prices for our contracts are above market prices at the time of settlement.

Acquisitions and Divestitures of Properties

2021 Acquisitions and Divestitures

On April 22, 2021, we announced the acquisition of all the overriding royalty interest assets of SandRidge Mississippian Trust I (the "Trust"). The gross purchase price was $4.9 million (net $3.6 million, given our 26.9% ownership of the Trust).

On February 5, 2021, we sold all of our oil and natural gas properties and related assets of the North Park Basin ("NPB") in Colorado for a purchase price of $47 million in cash. Net proceeds were $39.7 million in cash as a result of customary effective to close date adjustments and a $0.8 million post-close adjustment made during the second half of the year. The sale resulted in an $18.9 million gain after the post-close adjustment.

Oil, Natural Gas and NGL Production and Pricing

The table below presents production and pricing information for the years ended December 31, 2022 and 2021.

	Year Ended December 31,			
	2022	2021	Change	% Change
Production data (in thousands)				
Oil (MBbls)	949	957	(8)	(1)%
NGL (MBbls)	1,997	2,267	(270)	(12)%
Natural gas (MMcf)	21,101	21,417	(316)	(1)%
Total volumes (MBoe)	6,463	6,793	(330)	(5)%
Average daily total volumes (MBoe/d)	17.7	18.6	(0.9)	(5)%
Average prices—as reported (1)				
Oil (per Bbl)	$ 92.21	$ 65.10	$ 27.11	42 %
NGL (per Bbl)	$ 31.88	$ 22.42	$ 9.46	42 %
Natural gas (per Mcf)	$ 4.88	$ 2.60	$ 2.28	88 %
Total (per Boe)	$ 39.34	$ 24.86	$ 14.48	58 %
Average prices—including impact of derivative contract settlements				
Oil (per Bbl)	$ 92.21	$ 65.10	$ 27.11	42 %
NGL (per Bbl)	$ 31.72	$ 22.28	$ 9.44	42 %
Natural gas (per Mcf)	$ 4.97	$ 2.51	$ 2.46	98 %
Total (per Boe)	$ 39.58	$ 24.53	$ 15.05	61 %

(1) Prices represent actual average prices for the periods presented and do not include the impact of derivative transactions.

The table below presents production by area of operation for the years ended December 31, 2022 and 2021.

	Year Ended December 31,			
	2022		2021	
	Production (MBoe)	% of Total Production	Production (MBoe)	% of Total Production
Mid-Continent	6,463	100.0 %	6,726	99.0 %
North Park Basin	—	— %	67	1.0 %
Total	6,463	100.0 %	6,793	100.0 %

Revenues

Consolidated revenues for the years ended December 31, 2022 and 2021 are presented in the table below (in thousands).

	Year Ended December 31,			
	2022	2021	Change	% Change
Revenues				
Oil	$ 87,528	$ 62,297	$ 25,231	41 %
NGL	63,663	50,836	12,827	25 %
Natural gas	103,067	55,749	47,318	85 %
Total revenues	$ 254,258	$ 168,882	$ 85,376	51 %

Variances in oil, natural gas and NGL revenues attributable to changes in the average prices received for our production and total production volumes sold for the years ended December 31, 2022 and 2021 are shown in the table below (in thousands):

2021 oil, natural gas and NGL revenues	$	168,882
Change due to production volumes in 2022		(12,982)
Change due to average prices in 2022		98,358
2022 oil, natural gas and NGL revenues	$	254,258

Oil, natural gas and NGL revenues increased primarily due to improvements in realized commodity prices. Production volumes for the year ended December 31, 2022 decreased slightly due to the natural declines of our producing wells, which were partially offset from the production from our well reactivations and new well activity for the year.

Operating Expenses

Operating expenses for the years ended December 31, 2022 and 2021 consisted of the following (in thousands):

	Year Ended December 31,						
		2022		2021		Change	% Change
Lease operating expenses	$	41,286	$	35,999	$	5,287	14.7 %
Production, ad valorem, and other taxes		15,880		9,918		5,962	60.1 %
Depreciation and depletion—oil and natural gas		11,542		9,372		2,170	23.2 %
Depreciation and amortization—other		6,342		6,073		269	4.4 %
Total operating expenses	$	75,050	$	61,362	$	13,688	22.3 %
Lease operating expenses ($/Boe)	$	6.39	$	5.30	$	1.09	20.6 %
Production, ad valorem, and other taxes ($/Boe)	$	2.46	$	1.46	$	1.00	68.6 %
Depreciation and amortization—oil and natural gas ($/Boe)	$	1.79	$	1.38	$	0.41	29.7 %
Production, ad valorem, and other taxes (% of oil, natural gas, and NGL revenue)		6.2 %		5.9 %		0.4 %	5.5 %

The increase in lease operating expenses was primarily due to inflationary pressures, a higher number of producing wells and higher workover expenses due to our well reactivation program during the year ended December 31, 2022.

Production, ad valorem, and other taxes increased primarily due to the increase in production taxes as a result of increased revenues.

The increase in depreciation and depletion for oil and natural gas properties was primarily the result of increased capital expenditures from higher drilling and completion activity which increased our depletion rate.

Full cost pool impairment. We did not record a full cost ceiling limitation impairment for the years ended December 31, 2022 or 2021.

Calculation of the full cost ceiling test is based on, among other factors, trailing twelve-month SEC prices as adjusted for price differentials and other contractual arrangements. The SEC prices utilized in the calculation of proved reserves included in the full cost ceiling test at December 31, 2022 were $93.67 per barrel of oil and $6.36 per MMBtu of natural gas, before price differential adjustments.

Based on the SEC prices over the twelve months ended March 1, 2023, we anticipate the SEC prices utilized in the March 31, 2023 full cost ceiling test may be $90.97 per barrel of oil and $5.96 per MMBtu of natural gas, (the "estimated first quarter prices"). Applying these estimated first quarter prices, and holding all other inputs constant to those used in the calculation of our December 31, 2022 ceiling test, no full cost ceiling limitation impairment is indicated for the first quarter of 2023.

However, a full cost ceiling limitation impairment may still be realized in the first quarter of 2023 and in subsequent quarters based on the outcome of numerous other factors such as additional declines in the actual trailing twelve-month SEC prices, production, lower commodity prices, changes in estimated future development costs and operating expenses, and other revisions to our proved reserves. Any such ceiling test impairments in 2023 could be material to our net earnings.

Full cost pool impairments have no impact to our cash flow or liquidity.

Other Operating Expenses

Other operating expenses for the years ended December 31, 2022 and 2021 consisted of the following (in thousands):

	Year Ended December 31,			
	2022	2021	Change	% Change
General and administrative	$ 9,449	$ 9,675	(226)	(2.3)%
Restructuring expenses	382	792	(410)	(51.8)%
Employee termination benefits	—	49	(49)	(100.0)%
(Gain) loss on derivative contracts	(5,975)	2,251	(8,226)	(365.4)%
(Gain) loss on sale of assets	—	(18,952)	18,952	(100.0)%
Other operating expense (income)	(99)	(382)	283	(74.1)%
Total other operating expenses	$ 3,757	$ (6,567)	$ 10,324	(157.2)%

General and administrative expenses decreased for the year ended December 31, 2022 compared to the year ended December 31, 2021 due to continued efforts of cost control initiatives.

Restructuring expenses represent fees and costs associated with our predecessor company's 2016 bankruptcy filing and our exit from NPB in Colorado.

The following table summarizes derivative activity for the years ended December 31, 2022 and 2021 (in thousands):

	Year Ended December 31,	
	2022	2021
(Gain) loss on derivative contracts	$ (5,975)	$ 2,251
Cash paid (received) on settlements	$ (1,525)	$ 2,230

Our derivative contracts are not designated as accounting hedges and, as a result, changes in the fair value of our commodity derivative contracts are recorded quarterly as a component of operating expenses. Internally, management views the settlement of commodity derivative contracts at contractual maturity as adjustments to the price received for oil and natural gas production to determine "effective prices." In general, cash is received on settlement of contracts due to lower oil and natural gas prices at the time of settlement compared to the contract price for our commodity derivative contracts, and cash is paid on settlement of contracts due to higher oil and natural gas prices at the time of settlement compared to the contract price for our commodity derivative contracts. See Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" of this report for additional discussion of our commodity derivatives.

Gain on sale of assets for the year ended December 31, 2021 relates to the sale of our NPB assets in Colorado in February 2021. See "Note 3-Acquisitions, Divestitures and Disposal of Assets and Oil and Gas Properties."

Interest (income) expense, net for the years ended December 31, 2022 and 2021 consisted of the following (in thousands):

	Year Ended December 31,	
	2022	2021
Interest expense		
Interest expense on debt and letters of credit	$ 37	$ 377
Interest expense on right of use assets	36	26
Write off of debt issuance costs	—	174
Amortization of debt issuance costs, premium and discounts	—	57
Capitalized interest	—	(252)
Interest expense - other	143	25
Total	216	407
Less: interest income	(2,026)	(3)
Total interest (income) expense, net	$ (1,810)	$ 404

Interest (income) expense, net during the year ended December 31, 2022 is primarily comprised of interest income received from cash deposits partially offset by interest paid on royalty obligations of $0.1 million, interest on vehicle leases and letters of credit. Interest expense incurred during the year ended December 31, 2021 is primarily comprised of interest and fees paid on the 2020 Credit Facility. The 2020 Credit Facility has been fully repaid and terminated as of September 2, 2021. As a result of the termination of the 2020 Credit Facility, $0.2 million of deferred financing costs were expensed to Interest expense.

Other income (expense), net

Other income (expense), net for the years ended December 31, 2022 and 2021 is reflected in the table below (in thousands):

	Year Ended December 31,	
	2022	2021
Other income (expense), net		
Other income, net	$ 378	$ 3,055
Total other income	$ 378	$ 3,055

The Other income (expense), net line item for the year ended December 31, 2022 is primarily comprised of gains on the sale of fleet vehicles and the removal of previously accrued liabilities due to a change in estimate. For the year ended December 31, 2021, Other income (expense), net is primarily comprised of the removal of $2.4 million of an allowance for doubtful accounts as a result of the $2.4 million being collected in October 2021.

Liquidity and Capital Resources

At December 31, 2022, our cash and cash equivalents, including restricted cash, was $257.5 million. For the next twelve months, we expect to have ample liquidity with cash on hand and cash from operations. As of March 8, 2023, the Company had no outstanding term or revolving debt obligations.

Our commodity derivative contracts are subject to credit risk of our counterparties being financially able to settle the transaction. We monitor the credit ratings of our derivative counterparties and consider our counterparties' credit default risk ratings in determining the fair value of our derivative contracts. However, any future failures by one or more counterparties could negatively impact our cash flow from operations.

Working Capital and Sources and Uses of Cash

Our principal sources of liquidity for 2022 included cash flow from operations and cash on hand.

Our working capital increased to $241.6 million at December 31, 2022, compared to $97.7 million at December 31, 2021. The positive impact on working capital resulted primarily from an increase in cash and cash equivalents at December 31, 2022 as a result of cash flows from operations, partially offset by increased accrued liabilities driven largely by our increased capital expenditure activity in 2022.

We intend to spend between $26 million and $35 million in our 2023 capital budget plan, excluding any expenditures for acquisitions. We intend to fund capital expenditures and other commitments for the next 12 months using cash flows from our operations and cash on hand. We will endeavor to keep our capital spending within or very close to our projected cash flows from operations subject to changing industry conditions or events.

Cash Flows

Our cash flows from operations are substantially dependent on current and future prices for oil and natural gas, which historically have been, and may continue to be, volatile. For example, during the period from January 2018 through December 2022, the NYMEX WTI settled price for oil fluctuated between a high of $123.64 per Bbl and a low of $(36.98) per Bbl, and the month-end NYMEX Henry Hub settled price for gas fluctuated between a high of $24.74 per Mcf and a low of $1.38 per Mcf.

If oil or natural gas prices decline from current levels, they could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil, natural gas and NGL reserves that may be economically produced. Further, if our future capital expenditures are limited or deferred, or we are unsuccessful in developing reserves and adding production through our capital program, the value of our oil and natural gas properties, financial condition and results of operations could be adversely affected.

Cash flows for the years ended December 31, 2022, and 2021 are presented in the following table and discussed below (in thousands):

	Year Ended December 31,	
	2022	2021
Cash flows provided by operating activities	$ 164,696	$ 110,260
Cash flows provided by (used in) investing activities	(45,117)	22,973
Cash flows (used in) financing activities	(1,635)	(21,975)
Net increase in cash, cash equivalents and restricted cash	$ 117,944	$ 111,258

Cash Flows from Operating Activities

The $54.4 million increase in operating cash flows for the year ended December 31, 2022 compared to 2021, is primarily due to increased revenues which is the result of improved commodity prices as discussed above, offset by a slight decrease in production. The changes in operating assets and liabilities do not include changes in accounts payable or accrued expenses attributable to capital expenditures noted in the capital expenditure table below.

See "Consolidated Results of Operations" for further analysis of the changes in revenues and operating expenses.

Cash Flows from Investing Activities

During the year ended December 31, 2022, cash flows used in investing activities primarily reflects capital expenditures of $44.1 million related to drilling, capital workovers, well reactivations, and inventory purchases and $1.4 million related to an acquisition of proved reserves. Cash outflows were partially offset by $0.4 million of proceeds from the sale of assets.

During the year ended December 31, 2021, cash flows provided by investing activities primarily reflects $38.2 million of net cash proceeds primarily from the sale of the NPB assets partially offset by capital expenditures of $11.6 million and the acquisition of overriding royalty interests for $3.6 million.

See "Note 3— Acquisitions, Divestitures and Disposal of Assets and Oil and Gas Properties" to the accompanying consolidated financial statements included in Item 8 of this report for additional information.

Capital Expenditures.

Our capital expenditures for the years ended December 31, 2022 and 2021, are summarized below (in thousands):

	Year Ended December 31,	
	2022	2021
Capital Expenditures		
Drilling and completions	$ 38,077	$ 1,087
Capital workovers	10,322	8,958
Leasehold and geophysical	809	905
Capital expenditures, excluding acquisitions (on an accrual basis)	49,208	10,950
Acquisitions	1,431	3,545
Current year total capital expenditures, including acquisitions	50,639	14,495
Change in capital accruals	(5,123)	633
Total cash paid for capital expenditures	$ 45,516	$ 15,128

Capital expenditures, excluding acquisitions, for development activities increased for the year ended December 31, 2022 compared to 2021, which is in line with the planned drilling, completion, capital workover and well reactivation program.

Cash Flows from Financing Activities

Our financing activities used $1.6 million of cash for the year ended December 31, 2022, consisted primarily of $1.2 million of cash used for tax withholdings paid in exchange for shares withheld on employee vested stock awards that were settled by net exercise, and finance lease payments of $0.5 million offset by $0.1 million of proceeds from the exercise of stock options. Net exercises of stock awards allows the holder of a stock award to tender back to us a number of shares at fair value upon the vesting of such stock award, that equals the employee payroll tax obligation due. We then remit a cash payment to the relevant taxing authority on behalf of the employee for their payroll tax obligations resulting from the vesting of their stock award.

Our financing activities used $22.0 million in of cash for the year ended December 31, 2021, consisting primarily of repayments of borrowings under the 2020 Credit Facility of $20.0 million, finance lease payments of $1.0 million and cash used for tax withholdings paid in exchange for shares withheld on employee vested stock awards that were settled by net exercise of $0.9 million.

Share Repurchase Program

On August 16, 2021, our Board approved the initiation of a share repurchase program authorizing us to purchase up to an aggregate of $25.0 million of our common stock beginning as early as August 16, 2021. We did not repurchase any common stock under the Program during the year ended 2022.

Contractual Obligations and Off-Balance Sheet Arrangements

At December 31, 2022, our contractual obligations included asset retirement obligations and short and long-term leases. Additionally, we have certain financial instruments representing potential commitments that were incurred in the normal course of business to support our operations, including surety bonds. The underlying liabilities insured by these instruments are reflected in our balance sheets, where applicable. Therefore, no additional liability is reflected for the surety bonds or other instruments.

As of December 31, 2022, we had future contractual payment commitments under various agreements, which are summarized below. The short-term leases and operating lease are not recorded in the accompanying consolidated balance sheets.

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In thousands)		
Asset retirement obligations (1)	$ 63,709	$ 16,074	$ —	$ 127	$ 47,508
Operating lease	167	167	—	—	—
Short-term leases	2,076	2,076	—	—	—
Finance lease	1,059	459	600	—	—
Total	$ 67,011	$ 18,776	$ 600	$ 127	$ 47,508

(1) Asset retirement obligations are based on estimates and assumptions that affect the reported amounts as of December 31, 2022. These estimates and assumptions can be inherently unpredictable and may differ from actual results given the uncertainty of when we may be required to plug and abandon a well or retire an asset. As a result, we may not incur all of the estimated costs for the current asset retirement obligation as depicted above. During the year ended December 31, 2022, plugging and abandonment costs incurred were $2.6 million.

Valuation Allowance

Upon emergence from bankruptcy and the application of fresh start accounting in 2016, our tax basis in property, plant, and equipment exceeded the book carrying value of our assets. Additionally, we had significant U.S. federal net operating losses remaining after the attribute reduction caused by the restructuring transactions. As such, the successor Company had significant deferred tax assets to consume upon emergence. In assessing the realizability of the deferred tax assets, we consider whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. In prior years, we determined that the deferred tax assets did not meet the more likely than not threshold of being utilized and thus recorded a valuation allowance. As of December 31, 2022, we have partially released our valuation allowance on our deferred tax assets by $64.5 million. We anticipate being able to utilize these deferred tax assets based on the generation of future income. A change in the estimate of future income could cause the valuation allowance to be adjusted in subsequent periods.

See "Note 13—Income Taxes" to the accompanying consolidated financial statements for additional discussion of income tax related matters.

Critical Accounting Estimates

The discussion and analysis of the Company's financial condition and results of operations are based upon the Company's consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the Company's financial statements requires management to make assumptions and prepare estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Estimates are based on historical experience and various other assumptions believed to be reasonable; however, actual results may differ significantly. The Company's critical accounting policies and additional information on significant estimates are discussed below. See "Note 1—Summary of Significant Accounting Policies" to the Company's accompanying consolidated financial statements in Item 8 of this report for additional discussion of significant accounting policies.

Proved Reserves. Approximately 95.0% of the Company's reserves were estimated by independent petroleum engineers as of December 31, 2022. Estimates of proved reserves are based on the quantities of oil, natural gas and NGLs that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond the Company's control. Estimating reserves is a complex process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data. The accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2022 and 2021, the Company revised its proved reserves from prior years' reports by approximately 8.1 MMBoe and 43.3 MMBoe, respectively, due to increases in SEC prices used to value reserves at the end of the applicable period, production performance indicating more (or less) reserves in place, larger (or smaller) reservoir size than initially estimated or additional proved reserve bookings within the original field boundaries among other factors. Estimates of proved reserves are key components of the Company's financial estimates used to determine depreciation and depletion on oil and natural gas properties and its full cost ceiling limitation. Future revisions to estimates of proved reserves may be material and could materially affect the Company's future depreciation, depletion and impairment expenses.

Depreciation and depletion of Oil and Natural Gas Properties. In accordance with full cost accounting rules, capitalized costs are amortized using the unit-of-production method. Under this method, depreciation and depletion is computed at the end of each quarter by multiplying total production for the quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the quarter.

Impairment of Oil and Natural Gas Properties. In accordance with full cost accounting rules, capitalized costs are subject to a limitation. The capitalized cost of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes and electrical infrastructure costs, may not exceed an amount equal to the ceiling limitation. The Company calculates its full cost ceiling limitation using SEC prices adjusted for basis or location differentials, held constant over the life of the reserves. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. Once incurred, a write-down cannot be reversed at a later date. The Company did not record any impairment for the years ended December 31, 2022 or 2021.

See "Consolidated Results of Operations" and "Note 9—Impairment" to the Company's accompanying consolidated financial statements in Item 8 of this report for a discussion of the Company's impairments.

Asset Retirement Obligations. Asset retirement obligations represent the estimate of fair value of the cost to plug, abandon and remediate the Company's wells at the end of their productive lives, in accordance with applicable federal and state laws. The Company estimates the fair value of an asset's retirement obligation in the period in which the liability is incurred (at the time the wells are drilled or acquired). Estimating future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. The Company employs a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions and requires significant judgment, including an inflation rate, its credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability based on third-party quotes and current actual costs. Inherent in the present value calculation are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Income Taxes. Deferred income taxes are recorded for temporary differences between the financial statement and income tax basis of assets and liabilities. Deferred tax assets are recognized for temporary differences that will be deductible in future years' tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years' tax returns. In assessing the realizability of the deferred tax assets, we consider whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. In prior years, we determined that the deferred tax assets did not meet the more likely than not threshold of being utilized and thus recorded a valuation allowance. As of December 31, 2022, we have partially released our valuation allowance on our deferred tax assets by $64.5 million. We anticipate being able to utilize these deferred tax assets based on the generation of future income. A change in the estimate of future income could cause the valuation allowance to be adjusted in subsequent periods.

New Accounting Pronouncements. For a discussion of recently adopted accounting standards and recent accounting standards not yet adopted, see "Note 1—Summary of Significant Accounting Policies" to the Company's accompanying consolidated financial statements in Item 8 of this report.

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

General

This discussion provides information about the financial instruments we use to manage commodity prices. All contracts are settled in cash and do not require the actual delivery of a commodity at settlement. Additionally, our exposure to credit risk and interest rate risk is also discussed.

Commodity Price Risk. Our most significant market risk relates to the prices we receive for oil, natural gas and NGLs. Due to the historical price volatility of these commodities, from time to time, depending upon our view of opportunities under the then-prevailing market conditions, we enter into commodity pricing derivative contracts for a portion of our anticipated production volumes for the purpose of reducing the variability of oil, natural gas and NGLs we receive.

We may use a variety of commodity-based derivative contracts, including fixed price swaps, basis swaps and collars. At December 31, 2022, the Company's open derivative contracts consisted of natural gas commodity derivative contracts under which we will receive a fixed price for the contract and pay a floating market price to the counterparty over a specified period for a contracted volume. These commodity derivative contracts consisted of the following:

	Notional	Units	Weighted Average Fixed Price per Unit
Natural Gas Price Swaps: January 2023 - March 2023	1,044,000	MMBtu	$ 8.39

Because we have not designated any of our derivative contracts as hedges for accounting purposes, changes in fair values of our derivative contracts are recognized as gains and losses in current period earnings. As a result, our current period earnings may be significantly affected by changes in the fair value of our commodity derivative contracts. Changes in fair value are principally measured based on a comparison of future prices to the contract price at the period-end.

The following table summarizes derivative activity for the years ended December 31, 2022 and 2021 (in thousands):

	Year Ended December 31, 2022	Year Ended December 31, 2021
(Gain) loss on derivative contracts	$ (5,975)	$ 2,251
Cash paid (received) on settlements	$ (1,525)	$ 2,230

See "Note 6—Derivatives" to the accompanying consolidated financial statements in Item 8 of this report for additional information regarding our commodity derivatives.

Credit Risk. We are exposed to credit risk related to counterparties to our derivative financial contracts. All of our derivative transactions have been carried out in the over-the-counter market. The use of derivative transactions in over-the-counter markets involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of our derivative transactions have an "investment grade" credit rating. We monitor the credit ratings of our derivative counterparties and consider our counterparties' credit default risk ratings in determining the fair value of our derivative contracts. Historically, derivative contracts have been with multiple counterparties to minimize exposure to any individual counterparty, and in addition our counterparties have been large financial institutions.

We do not require collateral or other security from counterparties to support derivative instruments. We have master netting agreements with our derivative contract counterparties, which allow us to net our derivative assets and liabilities by commodity type with the same counterparty. As a result of the netting provisions, our maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the commodity derivative contracts. Therefore, we are not required to post additional collateral under our commodity derivative contracts.

We are also exposed to credit risk related to the collection of receivables from our joint interest partners for their proportionate share of expenditures made on projects we operate. Historically, our credit losses on joint interest receivables have been immaterial.

Item 8. ***Financial Statements and Supplementary Data***

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Management's Report on Internal Control over Financial Reporting

Management of SandRidge Energy, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Internal control over financial reporting is a process designed by, or under the supervision of, the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013) (the COSO criteria). Based on management's assessment using the COSO criteria, management concluded the Company's internal control over financial reporting was effective as of December 31, 2022.

/s/ GRAYSON PRANIN	/s/ SALAH GAMOUDI
Grayson Pranin	**Salah Gamoudi**
President, Chief Executive Officer and Chief Operating Officer	**Executive Vice President, Chief Financial Officer and Chief Accounting Officer**

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of SandRidge Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of SandRidge Energy, Inc. and subsidiaries (the "Company") as of December 31, 2022, the related consolidated statements of operations, changes in stockholders' equity and cash flows for the year then ended and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2022, and the consolidated results of its operations and its cash flows for the year ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2023, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our 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 the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

Critical Audit Matters

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

The Impact of Proved Oil and Natural Gas Reserves on Depletion—Oil and Natural Gas and Forecasts of Taxable Income for the Assessment of the Realizability of Deferred Tax Assets

As described in Note 1, the Company follows the full cost method of accounting, pursuant to which oil and natural gas properties are amortized using the unit-of-production method over total proved reserves. For the year ended December 31, 2022, the Company recorded depletion related to its proved oil and natural gas properties of approximately $7.6 million.

The Company engages an independent reservoir engineering firm, to serve as a management specialist and to estimate substantially all its proved oil and natural gas reserves. To estimate the volume of proved oil and natural gas reserves and associated future net cash flows, management and their specialist make significant estimates and assumptions including forecasting the production decline rate of producing properties. The estimation of proved oil and natural gas reserves is impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required. Changes in significant assumptions or engineering data could have a significant impact on the amount of depletion for the Company's proved oil and natural gas properties and conclusions about realization of deferred tax assets. The impact of proved oil and natural gas reserves on forecasts of taxable income for the assessment of the realizability of deferred tax assets is further described below under Accounting for Income Taxes - Valuation Allowance on Deferred Tax Assets.

We identified the impact of proved oil and natural gas reserves on depletion and assessment of realizability of deferred tax assets as a critical audit matter due to use of significant judgment by management, including the use of specialist, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and increased extent of effort in performing procedures and evaluating audit evidence related to the significant assumptions used in developing those estimates of proved oil and natural gas reserves.

The primary procedures we performed to address this critical audit matter included:

- Testing the operating effectiveness of controls over the Company's estimation of oil and natural gas reserve quantities.
- Evaluating the knowledge, skill, and ability of the Company's third-party reservoir engineering specialist and their relationship to the Company, performing inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the proved reserve volumes and reading the reserve report prepared by the reservoir engineering specialist.
- Evaluating significant assumptions used by management and its specialist in developing the estimates of proved oil and natural gas reserves, including pricing differentials, future operations costs, future production rates and capital expenditures. The procedures performed included tests of the data inputs used by specialist for completeness and accuracy and an evaluation of the specialist's findings. The procedures performed included:

  - Testing the data inputs used by specialist for completeness and accuracy;
  - Testing the specialist's findings for mathematical accuracy; and
  - Performing analytical procedures on pricing, reserve quantities and cost estimates developed by management and its specialist. Those procedures entailed comparisons of:

    - prices to historical benchmark prices, adjusted for pricing differentials,
    - production forecasts to recent historical actual production,
    - projections of lease operating costs to recent historical costs incurred for a group of properties, and
    - projected production taxes to recent historical taxes incurred and to statutory tax rates.

  - Evaluating the accuracy of revenue and working interest percentages used in the reserve report by comparing a sample of such interests to the land records.
  - Performing retrospective review of historical estimates of proved oil and natural gas reserves to identify potential management bias in estimates.

Testing the accuracy of the Company's depletion calculation that included these proved reserves.

Accounting for Income Taxes – Valuation Allowance on Deferred Tax Assets

As described in Notes 1 and 13, deferred income taxes are recorded for temporary differences between the financial statement and income tax basis of assets and liabilities. Deferred tax assets are recognized for temporary differences that will be deductible in future years' tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years' tax returns. The Company has had a full valuation allowance against its deferred tax assets until December 31, 2022, when management concluded that it is more likely than not that a portion of the deferred tax assets will be realized, resulting in a deferred tax asset of $64.5 million and a deferred tax benefit of $64.5 million.

We identified the Company's estimate of the portion of deferred tax assets that is more likely than not to be realized as a critical audit matter. Specifically, the Company's evaluation of positive and negative evidence and estimates of future taxable income to determine the amount of valuation allowance for release involved significant management judgments. This in turn led to a high degree of auditor judgment, subjectivity, and increased extent of effort in performing procedures and evaluating audit evidence related to the weighing of positive and negative evidence and the significant assumptions used in developing estimates of future taxable income.

The primary procedures we performed to address this critical audit matter included:

- Testing the operating effectiveness of controls over management's determination of whether it is more likely than not that the deferred tax assets will be realized and development of estimates of future taxable income.

- With the assistance of internal income tax specialists:

    - Evaluating management's assessment and weighing of the positive and negative evidence utilized to conclude that a portion of a valuation allowance should be released; and
    - Assessing reasonableness of management's conclusion about tax benefits that are more likely than not to be realized after considering forecasted book/tax differences and utilization of net operating losses.

- Testing the reasonableness of the key assumptions and data in the taxable income forecast by:

    - Comparing forecasts of oil and natural gas production, pricing differentials, operating costs, production taxes, and ownership interests to the data inputs in Company's aforementioned proved oil and natural gas reserves;
    - Evaluating reasonableness of forecasted commodity pricing;
    - Comparing other projected operating costs and interest income to historical costs incurred or income earned; and
    - Assessing reasonableness of the forecast period used by management in its estimate of taxable income.

/s/ MOSS ADAMS LLP

Houston, Texas
March 15, 2023

We have served as the Company's auditor since 2022.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of SandRidge Energy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited SandRidge Energy, Inc. and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheet of SandRidge Energy, Inc. and subsidiaries as of December 31, 2022, the related consolidated statements of operations, changes in stockholders' equity and cash flows for year then ended, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated March 15, 2023 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting included in Item 9A. 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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/ MOSS ADAMS LLP

Houston, Texas
March 15, 2023

We have served as the Company's auditor since 2022.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of SandRidge Energy, Inc.

Opinion on the Financial Statements

We have audited the consolidated balance sheet of SandRidge Energy, Inc. and subsidiaries (the "Company") as of December 31, 2021, the related consolidated statements of operations, changes in stockholders' equity, and cash flows, for each of the two years in the period ended December 31, 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 as of December 31, 2021, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 10, 2022

We began serving as the Company's auditor in 2019. In 2022 we became the predecessor auditor.

SandRidge Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2022	December 31, 2021
	(In thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 255,722	$ 137,260
Restricted cash - other	1,746	2,264
Accounts receivable, net	34,735	21,505
Derivative contracts	4,429	—
Prepaid expenses	523	626
Other current assets	7,747	80
Total current assets	304,902	161,735
Oil and natural gas properties, using full cost method of accounting		
Proved	1,507,690	1,454,016
Unproved	11,516	12,255
Less: accumulated depreciation, depletion and impairment	(1,380,574)	(1,373,217)
	138,632	93,054
Other property, plant and equipment, net	92,244	97,791
Other assets	190	332
Deferred tax assets	64,529	—
Total assets	$ 600,497	$ 352,912
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$ 46,335	$ 45,779
Asset retirement obligations	16,074	17,606
Derivative contracts	—	21
Other current liabilities	870	627
Total current liabilities	63,279	64,033
Asset retirement obligations	47,635	41,762
Other long-term obligations	1,661	1,795
Total liabilities	112,575	107,590
Commitments and contingencies (Note 12)		
Stockholders' Equity		
Common stock, $0.001 par value; 250,000 shares authorized; 36,868 issued and outstanding at December 31, 2022 and 36,675 issued and outstanding at December 31, 2021	37	37
Warrants	—	88,520
Additional paid-in capital	1,151,689	1,062,737
Accumulated deficit	(663,804)	(905,972)
Total stockholders' equity	487,922	245,322
Total liabilities and stockholders' equity	$ 600,497	$ 352,912

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,		
	2022	2021	2020
	(In thousands, except per share amounts)		
Revenues			
Oil, natural gas and NGL	$ 254,258	$ 168,882	$ 114,450
Other	—	—	526
Total revenues	254,258	168,882	114,976
Expenses			
Lease operating expenses	41,286	35,999	43,431
Production, ad valorem, and other taxes	15,880	9,918	9,634
Depreciation and depletion—oil and natural gas	11,542	9,372	50,349
Depreciation and amortization—other	6,342	6,073	7,736
Impairment	—	—	256,399
General and administrative	9,449	9,675	15,327
Restructuring expenses	382	792	2,733
Employee termination benefits	—	49	8,433
(Gain) loss on derivative contracts	(5,975)	2,251	(5,765)
Gain on sale of assets	—	(18,952)	(100)
Other operating (income) expense	(99)	(382)	306
Total expenses	78,807	54,795	388,483
Income (loss) from operations	175,451	114,087	(273,507)
Other (expense) income			
Interest income (expense), net	1,810	(404)	(1,998)
Other income (expense), net	378	3,055	(2,494)
Total other income (expense)	2,188	2,651	(4,492)
Income (loss) before income taxes	177,639	116,738	(277,999)
Income tax (benefit)	(64,529)	—	(646)
Net income (loss)	$ 242,168	$ 116,738	$ (277,353)
Net income (loss) per share			
Basic	$ 6.59	$ 3.21	$ (7.77)
Diluted	$ 6.52	$ 3.13	$ (7.77)
Weighted average number of common shares outstanding			
Basic	36,745	36,393	35,689
Diluted	37,154	37,271	35,689

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity

	Common Stock		Warrants		Additional Paid-In Capital	Accumulated Deficit	Total
	Shares	Amount	Shares	Amount			
				(In thousands)			
Balance at January 1, 2020	35,772	$ 36	6,659	$ 88,520	$1,059,253	$ (745,357)	$ 402,452
Issuance of stock awards, net of cancellations	96	—	—	—	—	—	—
Common stock issued for general unsecured claims	60	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	3,031	—	3,031
Issuance of warrants for general unsecured claims	—	—	75	—	—	—	—
Tax withholdings paid in exchange for shares withheld on employee vested stock awards	—	—	—	—	(64)	—	(64)
Net loss	—	—	—	—	—	(277,353)	(277,353)
Balance at December 31, 2020	35,928	36	6,734	88,520	1,062,220	(1,022,710)	128,066
Issuance of stock awards, net of cancellations	547	1	—	—	(1)	—	—
Common stock issued for general unsecured claims	200	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	1,417	—	1,417
Issuance of warrants for general unsecured claims	—	—	247	—	—	—	—
Tax withholdings paid in exchange for shares withheld on employee vested stock awards	—	—	—	—	(899)	—	(899)
Net Income	—	—	—	—	—	116,738	116,738
Balance at December 31, 2021	36,675	37	6,981	88,520	1,062,737	(905,972)	245,322
Issuance of stock awards, net of cancellations	193	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	1,603	—	1,603
Tax withholdings paid in exchange for shares withheld on employee vested stock awards		—	—	—	(1,177)	—	(1,177)
Warrants exercised	—	—	—	(2)	8	—	6
Cancellation of expired warrants	—	—	(6,981)	(88,518)	88,518	—	—
Net Income	—	—	—	—	—	242,168	242,168
Balance at December 31, 2022	36,868	$ 37	—	$ —	$1,151,689	$ (663,804)	$ 487,922

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Year Ended December 31, 2022	2021	2020
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income (loss)	$ 242,168	$ 116,738	$ (277,353)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Provision for doubtful accounts	—	(2,329)	3,202
Depreciation, depletion and amortization	17,884	15,445	58,085
Impairment	—	—	256,399
Deferred income taxes	(64,529)	—	—
Debt issuance costs amortization	—	57	792
Write off of debt issuance costs	—	174	—
(Gain) loss on derivative contracts	(5,975)	2,251	(5,765)
Cash (paid) received on settlement of derivative contracts	1,525	(2,230)	5,879
Gain on sale of assets	—	(18,952)	(100)
Stock-based compensation	1,526	1,394	3,012
Other	153	144	149
Changes in operating assets and liabilities increasing (decreasing) cash			
Receivables	(13,211)	841	5,867
Prepaid expenses	(1,507)	2,264	452
Other current assets	(5,378)	—	458
Other assets and liabilities, net	(129)	(1,212)	1,134
Accounts payable and accrued expenses	(5,246)	(2,241)	(12,968)
Asset retirement obligations	(2,585)	(2,084)	(3,081)
Net cash provided by operating activities	164,696	110,260	36,162
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment	(44,085)	(11,583)	(8,762)
Acquisitions of assets	(1,431)	(3,545)	(3,701)
Purchase of other property and equipment	(49)	(59)	—
Proceeds from sale of assets	448	38,160	37,556
Net cash (used in) provided by investing activities	(45,117)	22,973	25,093
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings	—	—	59,000
Repayments of borrowings	—	(20,000)	(96,500)
Debt issuance costs	—	(75)	(160)
Reduction of financing lease liability	(541)	(1,024)	(1,233)
Proceeds from exercise of stock options	77	23	—
Tax withholdings paid in exchange for shares withheld on employee vested stock awards	(1,177)	(899)	(64)
Cash received on warrant exercises	6	—	—
Net cash (used in) financing activities	(1,635)	(21,975)	(38,957)
NET INCREASE IN CASH, CASH EQUIVALENTS and RESTRICTED CASH	117,944	111,258	22,298
CASH, CASH EQUIVALENTS and RESTRICTED CASH, beginning of year	139,524	28,266	5,968
CASH, CASH EQUIVALENTS and RESTRICTED CASH, end of year	$ 257,468	$ 139,524	$ 28,266

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

1. Summary of Significant Accounting Policies

Nature of Business. SandRidge Energy, Inc. is an oil and natural gas acquisition, development and production company headquartered in Oklahoma City, Oklahoma with a principal focus on developing and producing hydrocarbon resources in the United States.

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and its wholly owned or majority owned subsidiaries, including its proportionate share of the Royalty Trusts. All intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates. The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The more significant areas requiring the use of assumptions, judgments and estimates include: oil, natural gas and NGL reserves; impairment tests of long-lived assets; the carrying value of unproved oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; determinations of significant alterations to the full cost pool and related estimates of fair value used to allocate the full cost pool net book value to divested properties, as necessary; valuation allowances for deferred tax assets; income taxes; valuation of derivative instruments; contingencies; and accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ significantly from those estimates.

Going Concern Consideration. The accompanying consolidated financial statements are prepared in accordance with generally accepted accounting principles applicable to a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business.

Cash and Cash Equivalents. The Company considers all highly-liquid instruments with an original maturity of three months or less to be cash equivalents as these instruments are readily convertible to known amounts of cash and bear insignificant risk of changes in value due to their short maturity period. Additionally, the Company considers demand deposits or accounts that have the general characteristics of demand deposits where we may deposit additional funds at any time and also effectively withdraw funds at any time without prior notice or penalty to be cash equivalents.

Restricted Cash. The Company maintains funds related to collateralized letters of credit and secured credit cards.

Accounts Receivable, Net. The Company has receivables for sales of oil, natural gas and NGLs, as well as receivables related to the drilling, completion, and production of oil and natural gas, which have a contractual maturity of one year or less. An allowance for doubtful accounts has been established based on management's review of the collectability of the receivables in light of historical experience, the nature and volume of the receivables and other subjective factors. Accounts receivable are charged against the allowance, upon approval by management, when they are deemed uncollectible. Refer to Note 5 for further information on the Company's accounts receivable and allowance for doubtful accounts.

Fair Value of Financial Instruments. Certain of the Company's financial assets and liabilities are measured at fair value. Fair value represents the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The Company's financial instruments, not otherwise recorded at fair value, consist primarily of cash, restricted cash, prepaid expenses, trade receivables, and trade payables and accrued expenses. The carrying values of cash, restricted cash, trade receivables, trade payables and accrued expenses are considered to reflect fair values due to the short-term maturity of these instruments. See Note 4 for further discussion of the Company's fair value measurements.

Fair Value of Non-financial Assets and Liabilities. The Company also applies fair value accounting guidance to initially, or as events dictate, measure non-financial assets and liabilities such as those obtained through business acquisitions, property, plant and equipment and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances.

Under the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and natural gas production or other applicable sales estimates, operational costs and a risk-adjusted discount rate. The Company may use the present value of estimated future cash inflows and/or outflows, third-party offers or prices of comparable assets with consideration of current market conditions to fair value its non-financial assets and liabilities when necessary.

Derivative Financial Instruments. The Company enters into oil and natural gas derivative contracts to manage risks related to fluctuations in prices of its expected oil and natural gas production. The Company considers current and anticipated market conditions, planned capital expenditures, and any debt service requirements when determining whether to enter into oil and gas derivative contracts. The Company may also, from time to time, enter into interest rate swaps in order to manage risk associated with its exposure to variable interest rates.

The Company recognizes its derivative instruments as either assets or liabilities at fair value with changes in fair value recognized in earnings unless designated as a hedging instrument. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The related cash flow impact of the Company's derivative activities are reflected as cash flows from operating activities unless the derivative contract contains a significant financing element, in which case, cash settlements are classified as cash flows from financing activities in the consolidated statements of cash flows. See Note 6 for further discussion of the Company's derivatives.

Oil and Natural Gas Operations. The Company uses the full cost method to account for its oil and natural gas properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of oil, natural gas and NGL reserves are capitalized into a full cost pool. These capitalized costs include costs of unproved properties and internal costs directly related to the Company's acquisition, development, and exploration activities and capitalized interest. The Company capitalized gross internal costs of $0.3 million, $0.5 million and $0.7 million during the years ended December 31, 2022, 2021 and 2020, respectively. Capitalized costs are amortized using the unit-of-production method. Under this method, depreciation and depletion is computed at the end of each quarter by multiplying total production for the quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the quarter.

Costs associated with unproved properties are excluded from the amortizable cost base until it has been determined that proved reserves exist or a lease is impaired. Unproved properties are reviewed at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and amortized. The costs associated with unproved properties are primarily the costs to acquire unproved acreage. All items classified as unproved property are assessed, on an individual basis or as a group if properties are individually insignificant, on a quarterly basis for possible impairment. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and whether the proved reserves can be developed economically. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. Costs of seismic data are allocated to unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis.

Under the full cost method of accounting, total capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes and electrical infrastructure costs may not exceed the ceiling limitation. A ceiling limitation calculation is performed at the end of each quarter. If the ceiling limitation is exceeded, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' equity and typically results in lower depreciation and depletion expense in future periods. Once incurred, a write-down cannot be reversed at a later date.

The ceiling limitation calculation is prepared using SEC prices adjusted for basis or location differentials, held constant over the life of the reserves. If applicable, these prices would be further adjusted to include the effects of any fixed price arrangements for the sale of oil and natural gas. Derivative contracts that qualify and are designated as cash flow hedges are included in estimated future cash flows, although the Company historically has not designated any of its derivative contracts as cash flow hedges. The future cash outflows associated with future development or abandonment of wells are included in the computation of the discounted present value of future net revenues for purposes of the ceiling limitation calculation.

Sales and abandonments of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and NGL reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center, unless it results in a greater than 10% change to the depletion rate.

Property, Plant and Equipment, Net. Other capitalized costs, including other property and equipment, such as electrical infrastructure assets and buildings, are carried at cost or fair value established on the Emergence Date less applicable depreciation. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 7 to 39 years for buildings and 1 to 27 years for the electrical infrastructure assets and other equipment. When property and equipment components are disposed, the cost and the related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statements of operations.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that estimated future net operating cash flows directly related to the asset or asset group including disposal value is less than the carrying amount of the asset or asset group. Impairment is measured as the excess of the carrying amount of the impaired asset or asset group over its fair value. See Note 9 for further discussion of impairments.

Capitalized Interest. Interest is capitalized on assets being made ready for use using a weighted average interest rate based on the Company's borrowings outstanding during that time. During the year ended December 31, 2022 the Company did not capitalize any interest on unproved properties, while during the year ended December 31, 2021 the Company capitalized interest of approximately $0.3 million on unproved properties that were not currently being depreciated or depleted and on which exploration activities were in progress.

Debt Issuance Costs. The Company includes unamortized debt issuance costs, if any, in other assets in the consolidated balance sheets. Other debt issuance costs related to long-term debt, if any, are presented in the balance sheets as a direct deduction from the associated debt liability, if material. Debt issuance costs are amortized to interest expense over the term of the related debt. When debt is retired, any unamortized costs, if material are written off and included in gain or loss on extinguishment of debt.

Asset Retirement Obligations. The Company owns oil and natural gas assets that require expenditures to plug, abandon and remediate associated property at the end of their productive lives, in accordance with applicable federal and state laws. Liabilities for these asset retirement obligations are recorded at the estimated present value at the time the wells are drilled or acquired, with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until it is settled or the asset is sold and the liability is removed. Both the accretion and the depreciation are included in the consolidated statements of operations. The Company determines its asset retirement obligations by calculating the present value of estimated expenses related to the liability. Estimating future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. Inherent in the present value calculation are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. See Note 11 for further discussion of the Company's asset retirement obligations.

Revenue Recognition and Natural Gas Balancing. Sales of oil, natural gas and NGLs are recorded at a point in time when control of the oil, natural gas and NGL production passes to the customer at the inlet of the processing plant or pipeline, or the delivery point for onloading to a delivery truck, net of royalties, discounts and allowances, as applicable. Additionally, the Company deducts transportation costs from oil, natural gas and NGL revenues. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are included in production, ad valorem and other taxes in the consolidated statements of operations. See Note 15 for further information on the Company's accounting policies related to revenues.

The Company accounts for natural gas production imbalances using the sales method, which recognizes revenue on all natural gas sold even though the natural gas volumes sold may be more or less than the Company's ownership entitles it to sell. Liabilities are recorded for imbalances greater than the Company's proportionate share of remaining estimated natural gas reserves. The Company has recorded a liability for natural gas imbalance positions of $1.4 million at December 31, 2022 and 2021. The Company includes the gas imbalance positions in other long-term obligations in the consolidated balance sheets.

Allocation of Share-Based Compensation. Equity compensation provided to employees directly involved in exploration and development activities is capitalized to the Company's oil and natural gas properties. Equity compensation not capitalized is recognized in general and administrative expenses, production expenses, and other operating expense in the accompanying consolidated statements of operations.

Restructuring expenses. Restructuring expenses represent fees and costs associated with our outsourcing and relocation of certain corporate specific functions that are of a non-recurring nature, expenses related to our predecessor company's 2016 bankruptcy, and our exit from NPB in Colorado.

Income Taxes. Deferred income taxes reflect the net tax effects of temporary differences between the amounts of assets and liabilities reported for financial statement purposes and their tax basis. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized.

The Company has elected an accounting policy in which interest and penalties on income taxes resulting from the underpayment or late payment of income taxes due to a taxing authority or relating to income tax contingencies are presented as a component of the income tax provision, rather than as interest expense.

Earnings per Share. Basic earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of unvested restricted stock awards, performance share units, warrants, and stock options using the treasury method.

Under the treasury method, the amount of unrecognized compensation expense related to unvested stock-based compensation grants or the proceeds that would be received if the warrants were exercised are assumed to be used to repurchase shares at the average market price. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. See Note 19 for the Company's earnings per share calculation.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Environmental expenditures are expensed or capitalized, as appropriate, depending on future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Environmental liabilities related to future costs are recorded on an undiscounted basis when assessments and/or remediation activities are probable and costs can be reasonably estimated. See Note 12 for discussion of the Company's commitments and contingencies.

Concentration of Risk. We regularly maintain cash in excess of federally insured limits at financial institutions. Additionally, all of the Company's commodity derivative transactions have been carried out in the over-the-counter market, which involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparty for all of the Company's commodity derivative transactions have an "investment grade" credit rating. The Company monitors the credit ratings of its commodity derivative counterparties on an ongoing basis and considers their credit default risk ratings in determining the fair value of its commodity derivative contracts. Historically, the Company's commodity derivative contracts have been with multiple counterparties to minimize exposure to any individual counterparty.

The Company enters into master netting agreements with all of its commodity derivative counterparties, which allows the Company to net its commodity derivative assets and liabilities for like commodities and derivative instruments with the same counterparty. As a result of the netting provisions, the Company's maximum amount of loss under commodity derivative transactions due to credit risk was limited to the net amounts due from the counterparties under the commodity derivative contracts.

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payment for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners are primarily independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general was adversely affected, the ability of the joint interest partners to reimburse the Company could be adversely affected.

Purchasers of the Company's oil, natural gas and NGL production consist primarily of independent marketers, large oil and natural gas companies and gas pipeline companies. The number of available purchasers and markets in the areas where we sell our production reduces the risk that the loss of a single downstream customer would materially affect our sales. We do not have any material commitments to deliver fixed and determinable quantities of oil and natural gas in the future under existing sales contracts or sales agreements.

The Company had sales exceeding 10% of total revenues to the following oil and natural gas purchasers (in thousands):

		Sales	% of Revenue
December 31, 2022			
Targa Pipeline Mid-Continent West OK LLC	$	147,902	58.2 %
Plains Marketing, L.P.	$	76,342	30.0 %
December 31, 2021			
Targa Pipeline Mid-Continent West OK LLC	$	91,066	53.9 %
Plains Marketing, L.P.	$	51,204	30.3 %
December 31, 2020			
Plains Marketing, L.P.	$	40,058	34.8 %
Targa Pipeline Mid-Continent West OK LLC	$	38,287	33.3 %
Sinclair Crude Company	$	36,375	31.6 %

Recently Adopted Accounting Pronouncements. Accounting Standards Updates ("ASU") 2016-13 - In March 2016, the FASB issued ASU 2016-13, "Financial Instruments —Credit Losses (Topic 326) Measurement of Credit Losses on Financial Instruments," which 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 replaced the previously required incurred loss approach with an expected loss model for instruments measured at amortized cost. The Company adopted this ASU on January 1, 2020 using a modified retrospective approach; however, the impact was not material upon adoption.

ASU 2019-12 - In December 2019, the FASB issued ASU 2019-12, "Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes," which simplifies various aspects of accounting for income taxes, including requirements related to hybrid tax regimes, the tax basis step-up in goodwill obtained in a transaction that is not a business combination, separate financial statements of entities not subject to tax, the intraperiod tax allocation exception to the incremental approach, ownership changes in investments, interim-period accounting for enacted changes in tax laws, and year-to-date loss limitation in interim-period tax accounting. The standard is effective for interim and annual periods beginning after December 15, 2020, with early adoption permitted, and will be applied on a prospective basis. The ASU is effective for the Company beginning January 1, 2021 and resulted in no material impact on its consolidated financial statements.

Recent Accounting Pronouncements Not Yet Adopted. The FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting, amended by ASU 2022-06, Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848. This guidance provides optional practical expedients and exceptions for applying United States Generally Accepted Accounting Principles ("US GAAP") provisions to contracts, hedging relationships, and other transactions that reference LIBOR, or other reference rates expected to be discontinued because of reference rate reform, if certain criteria are met. The guidance in this update was effective upon its issuance. If elected, the guidance is to be applied prospectively through December 31, 2024. We are currently evaluating the effect the potential adoption of this ASU will have on our consolidated financial statements, if any.

2. Supplemental Cash Flow Information

Supplemental disclosures to the consolidated statements of cash flows are presented below (in thousands):

	Year Ended December 31,					
		2022		2021		2020
Supplemental Disclosure of Cash Flow Information						
Cash paid for interest, net of amounts capitalized	$	(215)	$	(177)	$	(1,260)
Cash received for income taxes	$	—	$	—	$	616
Supplemental Disclosure of Noncash Investing and Financing Activities						
Purchase of PP&E in accounts payable and accrued expenses	$	6,151	$	1,029	$	396
Right-of-use assets obtained in exchange for financing lease obligations	$	713	$	1,258	$	67
Carrying value of properties exchanged	$	—	$	—	$	3,890
Asset retirement obligation capitalized	$	86	$	18	$	309
Asset retirement obligation removed due to divestiture	$	(623)	$	(7,662)	$	(502)
Asset retirement obligation revisions	$	2,656	$	6,800	$	(17,192)

3. Acquisitions, Divestitures and Disposal of Assets and Oil and Gas Properties

2021 Acquisitions and Divestitures

On April 22, 2021, we announced the acquisition of all the overriding royalty interest assets of SandRidge Mississippian Trust I (the "Trust"). The gross purchase price was $4.9 million (net $3.6 million, given our 26.9% ownership of the Trust).

North Park Basin Sale

On February 5, 2021, the Company sold all of its oil and natural gas properties and related assets of the North Park Basin ("NPB"), in Colorado, for a purchase price of $47 million. The sale closed for net proceeds of $39.7 million in cash, which amounts to the purchase price of $47 million net of effective date to close date adjustments. Consequently, the Company allocated a portion of the full cost pool net book value, using the income approach, to the divested oil and gas properties and recognized a reduction of full cost pool assets of $22.0 million and a reduction of $4.6 million to its non-full cost pool assets. As the sale significantly altered the relationship between capitalized costs and proved reserves, the Company recognized a $19.7 million gain related to the assets sold. The gain represents net proceeds of $39.7 million coupled with the release of revenues in suspense of $0.5 million and the relief of asset retirement obligations of $6.1 million offset by the reduction of $26.6 million in oil and gas properties related to NPB. The Company recorded a decrease to the sales price of $0.8 million as a result of post-closing adjustments made during the second half of the year. As a result, Gain on sale of assets decreased to $18.9 million for the year ended December 31, 2021.

2020 Acquisitions and Divestitures

On September 10, 2020, the Company acquired all of the overriding royalty interests held by SandRidge Mississippian Royalty Trust II ("the Trust") for a net purchase price of $3.3 million, given our 37.6% ownership of the Trust. The Company accounted for this transaction as an asset acquisition and allocated the purchase price of the acquisition plus the transactions costs to oil and gas properties.

On August 31, 2020, the Company closed on the previously announced sale of its corporate headquarters building located in Oklahoma City, OK, for net proceeds of approximately $35.4 million. See Note 9 for additional discussion on the sale of the building.

4. Fair Value Measurements

The Company measures and reports certain assets and liabilities on a fair value basis and has classified and disclosed its fair value measurements using the levels of the fair value hierarchy noted below. The carrying values of cash, restricted cash, accounts receivable, prepaid expenses, certain other current assets, accounts payable and accrued expenses and other current liabilities and other long-term obligations included in the consolidated balance sheets approximated fair value at December 31, 2022 and December 31, 2021.

Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
Level 3	Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable for objective sources (*i.e.,* supported by little or no market activity).

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values, stated below, considers the market for the Company's financial assets and liabilities, the associated credit risk and other factors. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company has assets and liabilities classified in Level 2 of the hierarchy as of December 31, 2022 and 2021, as described below.

Level 2 Fair Value Measurements

Commodity Derivative Contracts. The fair values of the Company's oil and natural gas fixed price swaps are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors and discount rates, or can be corroborated from active markets. Fair value is determined through the use of a discounted cash flow model or option pricing model using the applicable inputs discussed above. The Company applies a weighted average credit default risk rating factor for its counterparties or gives effect to its credit default risk rating, as applicable, in determining the fair value of these derivative contracts. Credit default risk ratings are based on current published credit default swap rates.

Fair Value - Recurring Measurement Basis

The following tables summarize the Company's assets and liabilities measured at fair value on a recurring basis by the fair value hierarchy (in thousands):

December 31, 2022

	Fair Value Measurements				
	Level 1	Level 2	Level 3	Netting	Assets at Fair Value
Assets					
Commodity derivative contracts	$ —	$ 4,429	$ —	$ —	$ 4,429
Total	$ —	$ 4,429	$ —	$ —	$ 4,429

December 31, 2021

	Fair Value Measurements				
	Level 1	Level 2	Level 3	Netting(1)	Liabilities at Fair Value
Liabilities					
Commodity derivative contracts	$ —	$ 200	$ —	$ 179	$ 21
Total	$ —	$ 200	$ —	$ 179	$ 21

(1) Represents the impact of netting assets and liabilities with counterparties where the right of offset exists.

Transfers. During the years ended December 31, 2022, 2021 and 2020, the Company did not have any transfers between Level 1, Level 2 or Level 3 fair value measurements.

Fair Value of Non-Financial Assets and Liabilities

See Note 9 for discussion of the Company's impairment valuations.

5. Accounts Receivable

A summary of accounts receivable is as follows (in thousands):

	December 31,	
	2022	2021
Oil, natural gas and NGL sales	$ 21,839	$ 18,829
Joint interest billing	11,234	3,441
Other	3,689	1,262
Total accounts receivable	36,762	23,532
Less: allowance for doubtful accounts	(2,027)	(2,027)
Total accounts receivable, net	$ 34,735	$ 21,505

The following table presents the balance and activity in the allowance for doubtful accounts for the years ended December 31, 2022 and 2021 (in thousands):

	Year Ended December 31,	
	2022	2021
Beginning balance	$ 2,027	$ 4,356
Additions charged to costs and expenses	—	21
Deductions (1)	—	(2,350)
Ending balance	$ 2,027	$ 2,027

(1) Deductions represent collections of amounts for which an allowance had previously been established.

6. Derivatives

Commodity Derivatives

The Company is exposed to commodity price risk, which impacts the predictability of its cash flows from the sale of oil and natural gas. On occasion, the Company has attempted to manage this risk on a portion of its forecasted oil or natural gas production sales through the use of commodity derivative contracts.

The Company has not designated any of its derivative contracts as hedges for accounting purposes. All derivative contracts are recorded at fair value with changes in derivative contract fair values recognized as gain or loss on derivative contracts in the consolidated statements of operations. None of the Company's commodity derivative contracts may be terminated prior to contractual maturity solely as a result of a downgrade in the credit rating of a party to the contract. Commodity derivative contracts are settled on a monthly basis, and the commodity derivative contract valuations are adjusted to the mark-to-market valuation on a quarterly basis.

The following table summarizes derivative activity for the years ended December 31, 2022, 2021 and 2020 (in thousands):

	Year Ended December 31,		
	2022	2021	2020
(Gain) loss on derivative contracts	$ (5,975)	$ 2,251	$ (5,765)
Cash paid (received) on settlements	$ (1,525)	$ 2,230	$ (5,879)

Master Netting Agreements and the Right of Offset. As applicable, the Company has master netting agreements with all of its commodity derivative counterparties and has presented its derivative assets and liabilities with the same counterparty on a net basis by commodity type in the consolidated balance sheets. As a result of the netting provisions, the Company's maximum amount of loss under commodity derivative transactions due to credit risk is limited to the net amounts due from its counterparties. As of December 31, 2022, the counterparty to the Company's open commodity derivative contracts consisted of one financial institution.

The following tables summarize (i) the Company's commodity derivative contracts on a gross basis, (ii) the effects of netting assets and liabilities for which the right of offset exists based on master netting arrangements and (iii) for the Company's net derivative positions as of December 31, 2022 and 2021 (in thousands):

December 31, 2022

	Gross Amounts	Gross Amounts Offset	Amounts Net of Offset	Financial Collateral	Net Amount
Assets					
Derivative contracts - current	$ 4,429	$ —	$ 4,429	$ —	$ 4,429
Total	$ 4,429	$ —	$ 4,429	$ —	$ 4,429

December 31, 2021

	Gross Amounts	Gross Amounts Offset	Amounts Net of Offset	Financial Collateral	Net Amount
Liabilities					
Derivative contracts - current	$ 200	$ 179	$ 21	$ —	$ 21
Total	$ 200	$ 179	$ 21	$ —	$ 21

As of December 31, 2022, the Company's open derivative contracts consisted of natural gas commodity derivative contracts under which we will receive a fixed price for the contract and pay a floating market price to the counterparty over a specified period for a contracted volume. These commodity derivative contracts consisted of the following:

	Notional	Units	Weighted Average Fixed Price per Unit
Natural Gas Price Swaps: January 2023 - March 2023	1,044,000	MMBtu	$ 8.39

Because we did not designate any of our derivative contracts as hedges for accounting purposes, changes in the fair value of our derivative contracts were recognized as gains and losses in current period earnings. As a result, and as applicable, our current period earnings could have been significantly affected by changes in the fair value of our commodity derivative contracts. Changes in fair value were principally measured based on a comparison of future prices to the contract price at the end of the period.

Fair Value of Derivatives

The following table presents the fair value of the Company's derivative contracts on a net basis with same counterparty netting (in thousands):

Type of Contract	Balance Sheet Classification	December 31, 2022
Derivative assets		
Natural Gas	Current assets - Derivative Contracts	$ 4,429

Type of Contract	Balance Sheet Classification	December 31, 2021
Derivative liabilities		
Natural Gas and NGL price swaps	Current liabilities - Derivative Contracts	$ 21

See Note 4 for additional discussion of the fair value measurement of the Company's derivative contracts.

7. Leases

The Company determines if an arrangement is or contains a lease at inception. A lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment for a period of time in exchange for consideration. As most of the Company's leases do not provide an implicit rate, the Company's incremental borrowing rate was used as the discount rate when determining the present value of future payments. Lease assets are recognized based on the lease liability plus any prepaid lease payments and excluding lease incentives and initial direct costs incurred for the same periods. The Company's lease terms may include options to extend or terminate the lease when it is reasonably certain that option will be exercised. The Company recognizes right-of-use assets and current and non-current lease liabilities on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized. Lease expense for minimum lease payments is recognized on a straight-line basis over the lease term.

Capitalized operating leases are included in other assets, other current liabilities and other long-term obligations, and finance leases are included in other property, plant and equipment, other current liabilities and other long-term obligations on the accompanying consolidated balance sheet as of December 31, 2022 and 2021.

The Company had operating and financing leases for vehicles, office space and equipment outstanding during the year ended December 31, 2022 and 2021, which were not significant to the consolidated financial statements.

The components of lease costs recognized for the Company's right-of-use leases are shown below (in thousands):

	Year Ended December 31, 2022	Year Ended December 31, 2021	Year Ended December 31, 2020
Short-term lease cost (1)	$ 4,208	$ 892	$ 1,880
Financing lease cost	673	389	1,220
Operating lease cost	161	151	169
Total lease cost	$ 5,042	$ 1,432	$ 3,269

(1) During the year ended December 31, 2022, there were $3.3 million in short-term lease costs capitalized associated with our drilling rig lease. Portions of these costs were reimbursed to the Company by other working interest owners. There were no short-term lease costs capitalized as part of oil and natural gas properties during the years ended December 31, 2021 or 2020.

8. Property, Plant and Equipment

Property, plant and equipment consists of the following (in thousands):

	December 31, 2022	December 31, 2021
Oil and natural gas properties		
Proved	$ 1,507,690	1,454,016
Unproved	11,516	12,255
Total oil and natural gas properties	1,519,206	1,466,271
Less accumulated depreciation, depletion and impairment	(1,380,574)	(1,373,217)
Net oil and natural gas properties capitalized costs	138,632	93,054
Land	200	200
Electrical infrastructure	121,819	121,819
Non-oil and natural gas equipment	1,644	1,575
Buildings and structures	3,603	3,603
Financing Leases	1,468	1,384
Total	128,734	128,581
Less accumulated depreciation and amortization	(36,490)	(30,790)
Other property, plant and equipment, net	92,244	97,791
Total property, plant and equipment, net	$ 230,876	$ 190,845

The average rates used for depreciation and depletion of oil and natural gas properties were $1.18 per Boe in 2022, $0.78 per Boe in 2021 and $5.11 per Boe in 2020.

See Note 9 for discussion of impairment of other property, plant and equipment.

Costs Excluded from Amortization

Costs excluded from amortization were related to unproved properties and were $11.5 million and $12.3 million, at December 31, 2022 and 2021, respectively.

For leases that do not have existing production that would otherwise extend the lease term, the Company estimates that any associated unproved costs will be evaluated and transferred to the amortization base of the full cost pool within a three to five-year period from the original lease date. In addition, the Company's internal engineers evaluate all properties on a quarterly basis.

9. Impairment

The Company assesses the need to impair its oil and gas properties during its quarterly full cost pool ceiling limitation calculation. The Company analyzes various property, plant and equipment for impairment when certain triggering events occur by comparing the carrying values of the assets to their undiscounted future net cash flows. The full cost pool ceiling limitation and other assets were determined in accordance with the policies discussed in Note 1.

Impairment for the years ended December 31, 2022, 2021 and 2020 consists of the following (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Full cost pool ceiling limitation	$ —	$ —	$ 218,399
Other	—	—	38,000
	$ —	$ —	$ 256,399

During the years ended December 31, 2022 and 2021, the Company did not record a full cost limitation impairment charge. The ceiling limitation impairment charges recorded for the year ended December 31, 2020 resulted from various factors, including a decrease in proved reserve value driven by a significant decline in the trailing twelve-month weighted average oil and natural gas prices in the first, second and third quarters of 2020. See Note 20 for additional discussion of our oil and gas producing properties.

The asset impairment charge of $38.0 million recorded for the year ended December 31, 2020 resulted from the write down of the net carrying amount of the office headquarters building assets to their estimated fair value less estimated costs to sell the building. In May 2020, the Company entered into an agreement for the sale of its corporate headquarters building located in Oklahoma City, OK. The building sale closed on August 31, 2020.

In accordance with the applicable accounting guidance, FASB ASC 360-10-45-9, the Company reclassified its corporate headquarters building net carrying amount from Other property, plant and equipment, net, to Assets held for sale on the Consolidated Balance Sheet at June 30, 2020. The Company also reclassified the liabilities associated with the corporate headquarters building from Accounts payable and accrued expenses to Liabilities held for sale on the Consolidated Balance Sheet at June 30, 2020. Further, the Company recorded an impairment charge of $38.0 million in the three-month period ended June 30, 2020 to write down the net carrying amount of the office headquarters building assets to their estimated fair value less estimated costs to sell the building.

Prior to the sale of the corporate headquarters building, the carrying amount of the building was assessed for recoverability and impairment using undiscounted cash flow measures of the consolidated Company as prescribed under ASC 360-10-35, rather than fair value as prescribed under ASC 360-10-45-9.

10. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consist of the following (in thousands):

	December 31,	
	2022	2021
Accounts payable and other accrued expenses	$ 17,989	$ 13,727
Production payable	22,290	23,974
Payroll and benefits	3,471	3,942
Taxes payable	2,585	3,902
Drilling advances	—	234
Total accounts payable and accrued expenses	$ 46,335	$ 45,779

11. Asset Retirement Obligations

The following table presents the balance and activity of the Company's asset retirement obligations (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Beginning balance	$ 59,368	$ 57,168	$ 75,016
Liability incurred upon acquiring and drilling wells	86	18	309
Revisions in estimated cash flows (1)	2,656	6,800	(17,192)
Liability settled or disposed in current period (2)	(2,296)	(8,668)	(6,866)
Accretion (3)	3,895	4,050	5,901
Ending balance	63,709	59,368	57,168
Less: current portion	16,074	17,606	16,467
Asset retirement obligations, net of current	$ 47,635	$ 41,762	$ 40,701

(1) Revisions for the years ended December 31, 2022, 2021 and 2020 relate primarily to changes in estimated well lives and changes in plugging cost estimates.
(2) $6.1 million is related to the sale of NPB in February 2021.
(3) Included on the Depreciation and depletion - oil and natural gas line item on the Consolidated Statements of Operations.

12. Commitments and Contingencies

Included below is a discussion of the Company's various future commitments and contingencies as of December 31, 2022. The Company has provided accruals where necessary for contingent liabilities, based on ASC 450, Contingencies, when it has determined that a liability is probable and reasonably estimable. The Company continuously assesses the potential liability related to the Company's pending litigation and revises its estimates when additional information becomes available. Additionally, the Company currently expenses all legal costs as they are incurred. The commitments and contingencies under these arrangements are not recorded in the accompanying consolidated balance sheets.

Legal Proceedings. As previously disclosed, on May 16, 2016, the Company and certain of its direct and indirect subsidiaries (collectively, the "Debtors") filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). The Bankruptcy Court confirmed the joint plan of organization (the "Plan") of the Debtors on September 9, 2016, and the Debtors subsequently emerged from bankruptcy on October 4, 2016.

Pursuant to the Plan, claims against the Company were discharged without recovery in each of the following consolidated cases (the "Cases"):

• *In re SandRidge Energy, Inc. Securities Litigation*, Case No. 5:12-cv-01341-LRW, USDC, Western District of Oklahoma ("In re SandRidge Energy, Inc. Securities Litigation"); and

• *Ivan Nibur, Lawrence Ross, Jase Luna, Matthew Willenbucher, and the Duane & Virginia Lanier Trust v. SandRidge Mississippian Trust I, et al.*, Case No. 5:15-cv-00634-SLP, USDC, Western District of Oklahoma ("Lanier Trust")

Both cases were settled with all defendants except the SandRidge Mississippian Trust I ("the Trust"), which is being sued by a class of purchasers of units under Sections 11, 12(a)(2), and 15 of the Securities Act of 1933 and Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, and Rule 10b-5 promulgated thereunder, based on allegations that the Trust, made misrepresentations or omissions concerning various topics including the performance of wells operated by the Company. The Company is contractually obligated to indemnify the Trust for losses, claims, damages, liabilities and expenses, including reasonable costs of investigation and attorney's fees and expenses, which it is required to advance. Such indemnification is not covered by insurance . Considering the status of the Lanier Trust matter, and the facts, circumstances and legal theories relating thereto, the Company is not able to determine the likelihood of an outcome or provide an estimate of any reasonably possible loss or range of possible loss related thereto. However, such losses, if incurred, could be material. The Company has not established any liabilities relating to the Lanier Trust matter and believes that the plaintiffs' claims are without merit.

Separately, the Company had received a demand by two of the settling individual defendants to fund a proposed settlement of $17 million with those defendants. The Company refused and filed an action in Oklahoma state court seeking a declaratory judgment that the defendants were not entitled to any settlement. As a result of the Company's refusal to fund the settlement, separate insurance was triggered. The insurance carriers funded the settlement of $17 million and are seeking recovery from the Company in the State court action. The Company disputes any liability under this demand and intends to continue to vigorously defend against this claim. Considering the status of this matter, and the facts, circumstances and legal theories thereto, the Company is not able to determine the likelihood of an outcome. The Company has not established any liabilities relating to this matter.

In addition to the matters described above, the Company is involved in various lawsuits, claims and proceedings, which are being handled and defended by the Company in the ordinary course of business.

13. Income Taxes

The Company's income tax (benefit) provision consisted of the following components (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Current			
Federal	$ —	$ —	$ (646)
State	—	—	—
	—	—	(646)
Deferred			
Federal	(55,796)	—	—
State	(8,733)	—	—
	(64,529)	—	—
Total (benefit) provision	$ (64,529)	$ —	$ (646)

A reconciliation of the (benefit) provision for income taxes at the statutory federal tax rate to the Company's actual income tax (benefit) provision is as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Computed at federal statutory rate	$ 37,304	$ 24,404	$ (58,574)
State taxes, net of federal benefit	5,843	3,012	(10,898)
Non-deductible expenses	3	83	18
Stock-based compensation	23	(541)	643
Return to provision adjustments	1,015	(221)	(945)
Refund of AMT Sequestration	—	—	(646)
Change in statutory tax rate	25,499	—	—
Change in state net operating loss carryforwards	31,762	—	—
Change in valuation allowance	(165,978)	(26,733)	69,285
Other	—	(4)	471
Total (benefit) provision	$ (64,529)	$ —	$ (646)

Deferred income taxes are provided to reflect the future tax consequences of temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. In assessing the realizability of the deferred tax assets, we consider whether it is more likely than not that some or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. In prior years, we determined that the deferred tax assets did not meet the more likely than not threshold of being utilized and thus recorded a valuation allowance. As of December 31, 2022, we have partially released our valuation allowance on our deferred tax assets by $64.5 million. We anticipate being able to utilize these deferred tax assets based on the generation of future income. A change in the estimate of future income could cause the valuation allowance to be adjusted in subsequent periods. As of December 31, 2021 the Company had a full valuation allowance against its deferred tax asset.

Significant components of the Company's deferred tax assets and liabilities are as follows (in thousands):

	December 31, 2022	December 31, 2021
Deferred tax liabilities		
Investments (1)	$ —	$ —
Derivative contracts	—	—
Total deferred tax liabilities	—	—
Deferred tax assets		
Property, plant and equipment	89,090	181,037
Net operating loss carryforwards	373,702	440,332
Tax credits and other carryforwards	33,852	33,861
Asset retirement obligations	13,791	14,842
Investments (1)	165	106
Other	1,392	2,363
Total deferred tax assets	511,992	672,541
Valuation allowance	(447,463)	(672,541)
Net deferred tax asset	$ 64,529	$ —

(1) Includes the Company's deferred tax liability resulting from its investment in the Royalty Trusts.

Internal Revenue Code ("IRC") Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. As a result of the Chapter 11 reorganization and related transactions, the Company experienced an ownership change within the meaning of IRC Section 382 during 2016 that subjected certain of the Company's tax attributes, including net operating losses ("NOLs"), to an IRC Section 382 limitation. This limitation has not resulted in cash taxes for any period subsequent to the ownership change. Since the 2016 ownership change, the Company has generated additional NOLs and other tax attributes that are not currently subject to an IRC Section 382 limitation. The Company's ability to use NOLs and other tax attributes to reduce taxable income and income taxes could be materially impacted by a future IRC 382 ownership change. Future transactions involving the Company's stock including those outside of the Company's control could cause an IRC 382 ownership change resulting in a limitation on tax attributes currently not limited and a more restrictive limitation on tax attributes currently subject to the previous IRC 382 limitation.

As of December 31, 2022, the Company had approximately $1.6 billion of federal NOL carryforwards, net of NOLs expected to expire unused due to the 2016 IRC Section 382 limitation. Of the $1.6 billion of federal NOL carryforwards, $0.7 billion expire during the years 2025 through 2037, while $0.9 billion do not have an expiration date. In addition, the Company had approximately $1.1 billion of state NOL carryforwards, net of NOLs expected to expire unused due to the 2016 IRC Section 382 limitation. Of the $1.1 billion in state NOL carryforwards, approximately $200 million are derived from states the Company currently does not operate in. Of the remaining state NOL carryforwards, $643 million do not have an expiration date and $247 million expire during the years 2026 through 2037. Additionally, the Company had federal tax credits in excess of $33.5 million which begin expiring in 2029.

The Company did not have any unrecognized tax benefits at December 31, 2022, 2021 or 2020.

The Company's only taxing jurisdiction is the United States (federal and state). The Company's tax years 2018 to present remain open for federal examination. Additionally, tax years 2005 through 2017 remain subject to examination for the purpose of determining the amount of federal NOL and other carryforwards. The number of years open for state tax audits varies, depending on the state, but is generally from three to five years.

14. Equity

Capital Stock and Equity Awards. Our authorized capital stock consists of 300 million shares, which include 250 million shares of common stock, $0.001 par value per share and 50 million shares of preferred stock, par value $0.001 per share. At December 31, 2022, the Company had 36.9 million shares of common stock issued and outstanding, including an immaterial amount of shares of unvested restricted stock awards. The Company also has 0.3 million restricted stock units, an immaterial amount of performance share units and 0.2 million stock options outstanding at December 31, 2022 as discussed further in Note 16. At December 31, 2021, the Company had 36.7 million shares of common stock issued and outstanding, including 0.1 million shares of unvested restricted stock awards. The Company also had 0.4 million of restricted stock units, an immaterial amount of performance share units and 0.3 million stock options outstanding at December 31, 2021. At December 31, 2022 and 2021, there were no shares of preferred stock issued and outstanding.

Warrants. Since the fourth quarter of 2016, the Company issued approximately 4.9 million Series A warrants and 2.1 million Series B warrants to certain holders of general unsecured claims as defined in the 2016 bankruptcy reorganization plan. These warrants were exercisable until October 4, 2022 for one share of common stock per warrant at initial exercise prices of $41.34 and $42.03 per share, respectively, subject to adjustments pursuant to the terms of the warrants. The warrants contained customary anti-dilution adjustments in the event of any stock split, reverse stock split, reclassification, stock dividend or other distributions. During the year ended December 31, 2022, warrant holders exercised 103 Series A warrants and 44 Series B warrants for 147 shares of common stock. Upon expiration, the remaining 4.9 million Series A warrants and 2.1 million Series B warrants were cancelled and the carrying value was transferred to Additional paid-in capital in the accompanying consolidated balance sheets.

Share Repurchase Program. In August 2021, our Board of Directors approved the initiation of a share repurchase program (the "Program") authorizing us to purchase up to an aggregate of $25.0 million of our common stock beginning as early as August 16, 2021. The Program is in accordance with Rule 10b-18 of the Exchange Act. Subject to applicable rules and regulations, repurchases under the Program can be made from time to time in open markets at our discretion and in compliance with safe harbor provisions, or in privately negotiated transactions. The Program does not require any specific number of shares to be acquired, and can be modified or discontinued by the Board at any time. We did not repurchase any common stock under the Program during the year ended December 31, 2022.

The Tax Benefits Preservation Plan. On July 1, 2020, the Board declared a dividend distribution of one right (a "Right") for each outstanding share of Company common stock, par value $0.001 per share to stockholders of record at the close of business on July 13, 2020. Each Right entitles its holder, under certain circumstances, to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock of the Company, par value $0.001 per share, at an exercise price of $5.00 per Right, subject to adjustment. The description and terms of the Rights are set forth in the tax benefits preservation plan, dated as of July 1, 2020, between the Company and American Stock Transfer & Trust Company, LLC, as rights agent (and any successor rights agent, the "Rights Agent").

The Company adopted the Tax Benefits Preservation Plan, as amended on March 16, 2021, in order to protect shareholder value against a possible limitation on the Company's ability to use its tax net operating losses (the "NOLs") and certain other tax benefits to reduce potential future U.S. federal income tax obligations. The NOLs are a valuable asset to the Company, which may inure to the benefit of the Company and its stockholders. However, if the Company experiences an "ownership change," as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), its ability to fully utilize the NOLs and certain other tax benefits will be substantially limited and the timing of the usage of the NOLs and such other benefits could be substantially delayed, which could significantly impair the value of those assets. Generally, an "ownership change" occurs if the percentage of the Company's stock owned by one or more of its "five-percent shareholders" (as such term is defined in Section 382 of the Code) increases by more than 50 percentage points over the lowest percentage of stock owned by such stockholder or stockholders at any time over a three-year period. The Tax Benefits Preservation Plan is intended to prevent against such an "ownership change" by deterring any person or group from acquiring beneficial ownership of 4.9% or more of the Company's securities.

Subject to certain exceptions, the Rights become exercisable and trade separately from Common Stock only upon the "Distribution Time," which occurs upon the earlier of:

- the close of business on the tenth (10th) day after the "Stock Acquisition Date," which is (a) the first date of public announcement that a person or group of affiliated or associated persons (with certain exceptions, an "Acquiring Person") has acquired, or obtained the right or obligation to acquire, beneficial ownership of 4.9% or more of the outstanding shares of Common Stock (with certain exceptions) or (b) such other date, as determined by the Board, on which a person or group has become an Acquiring Person, or

- the close of business on the tenth (10th) business day (or later date as may be determined by the Board prior to such time as any person or group becomes an Acquiring Person) following the commencement of a tender offer or exchange offer which, if consummated, would result in a person or group becoming an Acquiring Person.

Any existing stockholder or group that beneficially owns 4.9% or more of Common Stock has been grandfathered at its current ownership level, but the Rights will not be exercisable if, at any time after the announcement of the Tax Benefits Preservation Plan, such stockholder or group increases its ownership of Common Stock by one share of Common Stock. Certain synthetic interests in securities created by derivative positions, whether or not such interests are considered to be ownership of the underlying Common Stock or are reportable for purposes of Regulation 13D of the Securities Exchange Act of 1934, as amended, are treated as beneficial ownership of the number of shares of Common Stock equivalent to the economic exposure created by the derivative position, to the extent actual shares of Common Stock are directly or indirectly held by counterparties to the derivatives contracts.

Until the earlier of the Distribution Time and the Expiration Time, the surrender for transfer of any shares of Common Stock will also constitute the transfer of the Rights associated with those shares. As soon as practicable after the Distribution Time, separate rights certificates will be mailed to holders of record of Common Stock as of the close of business on the Distribution Time. From and after the Distribution Time, the separate rights certificates alone will represent the Rights. Except as otherwise provided in the Tax Benefits Preservation Plan, only shares of Common Stock issued prior to the Distribution Time will be issued with Rights. The Rights are not exercisable until the Distribution Time.

The Tax Benefits Preservation Plan was approved at the 2021 annual meeting of stockholders on May 25, 2021.

In the event that any person or group (other than certain exempt persons) becomes an Acquiring Person (a "Flip-in Event"), each holder of a Right (other than any Acquiring Person and certain related parties, whose Rights automatically become null and void) will have the right to receive, upon exercise, shares of Common Stock having a value equal to two times the exercise price of the Right.

In the event that, at any time following the Stock Acquisition Date, any of the following occurs (each, a "Flip-over Event"):

- the Company consolidates with, or merges with and into, any other entity, and the Company is not the continuing or surviving entity

- any entity engages in a share exchange with or consolidates with, or merges with or into, the Company, and the Company is the continuing or surviving entity and, in connection with such share exchange, consolidation or merger, all or part of the outstanding shares of Common Stock are changed into or exchanged for stock or other securities of any other entity or cash or any other property; or

- the Company sells or otherwise transfers, in one transaction or a series of related transactions, fifty percent (50%) or more of the Company's assets, cash flow or earning power, each holder of a Right (except Rights which previously have been voided as described above) will have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the Right.

Shares Withheld for Taxes. The following table shows the number of shares withheld for taxes and the associated value of those shares. These shares were accounted for as treasury stock when withheld, and then immediately retired.

	Year Ended December 31,		
	2022	2021	2020
		(In thousands)	
Number of shares withheld for taxes	66	192	51
Value of shares withheld for taxes	$ 1,177	$ 899	$ 64

15. Revenues

The following table disaggregates the Company's revenue by source for the years ended December 31, 2022, 2021 and 2020 (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Oil (1)	$ 87,528	$ 62,297	$ 73,621
NGL	63,663	50,836	17,962
Natural gas	103,067	55,749	22,867
Other	—	—	526
Total revenues	$ 254,258	$ 168,882	$ 114,976

(1) Results include revenue from NPB from 2020 through February 5, 2021, the closing date of the NPB sale.

Oil, natural gas and NGL revenues. A majority of the Company's revenues come from sales of oil, natural gas and NGLs. In accordance with the contracts governing these sales, performance obligations to customers are satisfied and revenues are recorded at a point in time when control of the oil, natural gas and NGL production passes to the customer at the inlet of the processing plant or pipeline, or the delivery point for onloading to a delivery truck. As the Company's customers obtain control of the production prior to selling it to other end customers, the Company presents its revenues on a net basis, rather than on a gross basis.

Pricing for the Company's oil, natural gas and NGL contracts is variable and is based on volumes sold multiplied by either an index price, net of deductions, or a percentage of the sales price obtained by the customer, which is also based on index prices. The transaction price is allocated on a pro-rata basis to each unit of oil, natural gas or NGL sold based on the terms of the contract. Oil, natural gas and NGL revenues are also recorded net of royalties, discounts and allowances, and transportation costs, as applicable. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from revenues and are included in production, ad valorem, and other taxes expense in the consolidated statements of operations.

Revenues Receivable. The Company records an asset in accounts receivable, net on its consolidated balance sheet for revenues receivable from contracts with customers at the end of each period. Pricing for revenues receivable is estimated using current month crude oil, natural gas and NGL prices, net of deductions. Revenues receivable on operated properties are typically collected the month after the Company delivers the related production to its customers. As of December 31, 2022 and 2021, the Company had revenues receivable of $21.8 million and $18.8 million., respectively, and we did not record any bad debt expense on revenue receivable as of December 31, 2022 and 2021.

16. Share-Based Compensation

Share-Based Compensation

Omnibus Incentive Plan. The Omnibus Incentive Plan became effective on October 4, 2016 and authorizes the issuance of up to 4.6 million shares of SandRidge common stock.

Persons eligible to receive awards under the Omnibus Incentive Plan include non-employee directors of the Company, employees of the Company or any of its affiliates, and certain consultants and advisors to the Company or any of its affiliates.

The types of awards that may be granted under the Omnibus Incentive Plan include stock options, restricted stock, performance awards and other forms of awards granted or denominated in shares of common stock, as well as certain cash-based awards. At December 31, 2022, the Company had restricted stock awards, restricted stock units, performance share units and stock options outstanding under the Omnibus Incentive Plan. Forfeitures for these awards are recognized as they occur.

Restricted Stock Awards. The Company's restricted stock awards are equity-classified awards and are valued based upon the market value of the Company's common stock on the date of grant. Outstanding restricted shares at December 31, 2022 will generally vest over either a one-year period or three-year period with a remaining weighted average contractual period of 0.63 years and have $0.2 million of associated unrecognized compensation cost.

The following table presents a summary of the Company's unvested restricted stock awards:

	Number of Shares	Weighted-Average Grant Date Fair Value
	(In thousands)	
Unvested restricted shares outstanding at January 1, 2020	233	$ 12.66
Granted	105	$ 2.15
Vested	(174)	$ 11.53
Forfeited / Canceled	(50)	$ 15.97
Unvested restricted shares outstanding at December 31, 2020	114	$ 3.26
Granted	56	$ 5.26
Vested	(111)	$ 2.99
Forfeited / Canceled	(2)	$ 16.25
Unvested restricted shares outstanding at December 31, 2021	57	$ 5.26
Granted	18	$ 18.93
Vested (1)	(57)	$ 5.26
Forfeited / Canceled	—	$ —
Unvested restricted shares outstanding at December 31, 2022	18	$ 18.93

(1) The aggregate intrinsic value of restricted stock that vested during 2022 was approximately $1.4 million based on the stock price at the time of vesting.

Restricted Stock Units. The Company's restricted stock units awards are equity-classified awards and are valued based upon the market value of the Company's common stock on the date of grant. Outstanding restricted stock units at December 31, 2022 will generally vest over a three-year period with a remaining weighted average contractual period of 1.67 years and have $1.1 million associated unrecognized compensation cost at December 31, 2022.

The following table presents a summary of the Company's unvested restricted stock units:

	Number of Units	Weighted-Average Grant Date Fair Value
	(In thousands)	
Unvested restricted stock units outstanding at December 31, 2020	1,410	$ 1.10
Granted	178	$ 7.58
Vested (1)	(477)	$ 1.14
Forfeited / Canceled	(705)	$ 0.94
Unvested restricted stock units outstanding at December 31, 2021	406	$ 4.18
Granted	39	$ 13.51
Vested (1)	(175)	$ 3.61
Forfeited / Canceled	(18)	$ 5.51
Unvested restricted stock units outstanding at December 31, 2022	252	$ 5.93

(1) The aggregate intrinsic value of restricted stock units that vested during 2022 was approximately $3.3 million based on the stock price at the time of vesting.

Performance Share Units. The Company's performance share units awards are equity-classified awards and are valued based upon the market value of the Company's common stock on the date of grant. Outstanding performance share units at December 31, 2022 will generally vest over a three year period with a remaining weighted average contractual period of 0.20 years and an immaterial amount of unrecognized compensation cost at December 31, 2022.

The following table presents a summary of the Company's performance share units:

	Number of Units	Weighted-Average Grant Date Fair Value
	(In thousands)	
Unvested performance share units outstanding at January 1, 2020	92	$ 20.41
Granted	205	$ 1.66
Vested	(92)	$ 20.41
Forfeited / Canceled	—	
Unvested performance share units outstanding at December 31, 2020	205	$ 1.66
Granted	39	$ 5.01
Vested	(197)	$ 1.70
Forfeited / Canceled	(13)	$ 2.38
Unvested performance share units outstanding at December 31, 2021	34	$ 5.01
Granted	19	$ 13.51
Vested (1)	(34)	$ 5.01
Forfeited / Canceled	(2)	$ 13.51
Unvested performance share units outstanding at December 31, 2022	17	$ 13.51

(1) The aggregate intrinsic value of performance share units that vested during 2022 was approximately $0.5 million.

Stock Options

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's common stock and other factors. The Company uses historical data on the exercise of stock options, post-vesting forfeitures and other factors to estimate the expected term of the stock-based payments granted. The risk-free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant. Generally, stock options granted to employees and directors vest ratably over three years from the grant date and expire seven years from the date of grant. There were no stock options granted during the year ended December 31, 2022.

Assumptions	For the Year Ended December 31, 2021	For the Year Ended December 31, 2020
Risk-free interest rate	0.79 %	1.40 %
Expected dividend yield	— %	— %
Expected volatility	78.2 %	46.2 %
Expected term	5 years	2.75 years

The following table presents a summary of the Company's stock option activity for the years ended December 31, 2022, 2021 and 2020:

	Number of Shares (In thousands)	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term(years)	Aggregate Intrinsic Value (in millions)
Outstanding at January 1, 2020	—	$ —	—	$ —
Granted	245	—	—	—
Forfeited / Canceled	(154)	—	—	—
Outstanding at December 31, 2020	91	$ —	2.68	$ 0.24
Exercisable at December 31, 2020	—	$ —	—	$ —
Outstanding at December 31, 2020	91	$ —	2.68	$ 0.24
Granted	250	—	—	—
Exercised	(9)	$ 6.43	—	—
Expired	(1)	—	—	—
Forfeited / Canceled	(7)	—	—	—
Outstanding at December 31, 2021	324	$ —	7.80	$ 0.80
Exercisable at December 31, 2021	24	$ —	1.59	$ 0.19
Outstanding at December 31, 2021	324	$ —	7.80	$ 0.80
Granted	—	—	—	—
Exercised	(31)	$ 17.53	—	—
Expired	—	—	—	—
Forfeited / Canceled	(7)	—	—	—
Outstanding at December 31, 2022 (1)	286	$ —	7.64	$ 2.38
Exercisable at December 31, 2022	68	$ —	6.49	$ 0.64

(1) All outstanding stock options as of December 31, 2022 are expected to vest.

In August 2021 and February 2020, the Company granted nonqualified stock options. As of December 31, 2022, the total unrecognized compensation expense was $1.1 million and will be recognized over a weighted average period of 3.65 years. The Company issues new shares upon stock option exercises.

The following tables summarize the Company's share and incentive-based compensation for the years ended December 31, 2022, 2021 and 2020 (in thousands):

	Recurring Compensation Expense (1)	Executive Terminations (2)	Reduction in Force (2)	Total
Year Ended December 31, 2022				
Equity-classified awards:				
Restricted stock awards and units	$ 997	$ —	$ —	$ 997
Performance share units	215	—	—	215
Stock options	314	—	—	314
Total share-based compensation expense	1,526	—	—	1,526
Less: Capitalized compensation expense	—	—	—	—
Share and incentive-based compensation expense, net	$ 1,526	$ —	$ —	$ 1,526
Year Ended December 31, 2021				
Equity-classified awards:				
Restricted stock awards and units	$ 773	$ —	$ 11	$ 784
Performance share units	476	—	6	482
Stock options	128	—	—	128
Total share-based compensation expense	1,377	—	17	1,394
Less: Capitalized compensation expense	—	—	—	—
Share and incentive-based compensation expense, net	$ 1,377	$ —	$ 17	$ 1,394
Year Ended December 31, 2020				
Equity-classified awards:				
Restricted stock awards	$ 974	$ 508	$ 40	$ 1,522
Performance share units	211	1,276	—	1,487
Stock options	22	—	—	22
Total share-based compensation expense	1,207	1,784	40	3,031
Less: Capitalized compensation expense	(19)	—	—	(19)
Share and incentive-based compensation expense, net	$ 1,188	$ 1,784	$ 40	$ 3,012

(1) Recorded in general and administrative expense in the accompanying consolidated statements of operations.
(2) Recorded in employee termination benefits in the accompanying consolidated statements of operations.

17. Incentive and Deferred Compensation Plans

Annual Incentive Plan. The Annual Incentive Plan ("AIP") incorporates quantitative performance measures, strategic qualitative goals and competitive target award levels for management and employees for the 2022 and 2021 performance years. Incentive bonus awards for 2022 will be provided based on performance measures related to health, safety and environment, production, operating expenses, capital expenditures, general and administrative expenses, among other metrics and will be paid in 2023 at the discretion of the Board of Directors. As of December 31, 2022 and 2021, the Company accrued approximately $1.5 million and $2.1 million, respectively for AIP. AIP Payments totaling $2.1 million were paid in 2022 for the 2021 performance year and $2.1 million were paid in 2021 for the 2020 performance year.

401(k) Plan. The Company maintains a 401(k) retirement plan for its employees. Under this plan, eligible employees may elect to defer a portion of their earnings up to the maximum allowed by the IRS. For the years ended December 31, 2022, 2021 and 2020, the Company made matching contributions to the plan equal to 100% on the first 10% of employee deferred wages, excluding incentive compensation, totaling $0.8 million, $0.8 million and $1.1 million, respectively. Participants in the plan are immediately 100% vested in the discretionary employee contributions and related earnings on those contributions. The Company's matching contributions and related earnings vest based on years of service, with full vesting occurring on the fourth anniversary of employment.

18. Employee Termination Benefits

The following table presents a summary of employee termination benefits for the years ended December 31, 2022, 2021 and 2020 (in thousands):

	Cash	Share-Based Compensation (2)	Number of Shares	Total Employee Termination Benefits
Year Ended December 31, 2022				
Executive Employee Termination Benefits	$ —	$ —	—	$ —
Other Employee Termination Benefits	—	—	—	—
	$ —	$ —	—	$ —
Year Ended December 31, 2021				
Executive Employee Termination Benefits	$ —	$ —	—	$ —
Other Employee Termination Benefits	32	17	—	49
	$ 32	$ 17	—	$ 49
Year Ended December 31, 2020				
Executive Employee Termination Benefits (1)	$ 1,009	$ 1,784	159	$ 2,793
Other Employee Termination Benefits	5,600	40	4	5,640
	$ 6,609	$ 1,824	163	$ 8,433

(1) On July 1, 2020, the Company's then current Chief Financial Officer, Michael A. Johnson and Chief Operating Officer, John Suter, separated employment from the Company. As a result, the Company paid cash severance costs and incurred share-based compensation costs associated with these separations during 2020.

(2) Share-based compensation recognized in connection with the accelerated vesting of restricted stock awards due to the sale of the North Park assets for the year ended December 31, 2021 and performance share units upon the departure of certain executives and the reductions in workforce in 2020 reflects the remaining unrecognized compensation expense associated with these awards at the date of termination was recorded as employee termination benefits. The unrecognized compensation expense was calculated using the grant date fair value for restricted stock awards and performance share units. One share of the Company’s common stock was issued per performance share unit.

As of December 31, 2020, there were no longer any legacy employment contracts.

See Note 16 for additional discussion of the Company’s share-based compensation awards.

19. Earnings (Loss) per Share

The following table summarizes the calculation of weighted average common shares outstanding used in the computation of diluted earnings (loss) per share:

	Net Earnings (Loss)	Weighted Average Shares	Earnings (Loss) Per Share
	(In thousands, except per share amounts)		
Year Ended December 31, 2022			
Basic earnings per share	$ 242,168	36,745	$ 6.59
Effect of dilutive securities			
Restricted stock awards (1)	—	20	
Restricted share units (1)	—	285	
Performance share units (1)	—	20	
Stock Options (1)	—	84	
Warrants	—	—	
Diluted earnings per share	$ 242,168	37,154	$ 6.52
Year Ended December 31, 2021			
Basic earnings per share	$ 116,738	36,393	$ 3.21
Effect of dilutive securities			
Restricted stock awards (1)	—	58	
Restricted share units (1)	—	689	
Performance share units (1)	—	83	
Stock Options (1)	—	48	
Warrants (2)	—	—	
Diluted earnings per share	$ 116,738	37,271	$ 3.13
Year Ended December 31, 2020			
Basic loss per share	$ (277,353)	35,689	$ (7.77)
Effect of dilutive securities			
Restricted stock awards (2)	—	—	
Restricted share units (2)	—	—	
Performance share units (2)	—	—	
Stock Options (2)	—	—	
Warrants (2)	—	—	
Diluted loss per share	$ (277,353)	35,689	$ (7.77)

(1) The incremental shares of potentially dilutive restricted stock awards, restricted stock units, performance share units and stock options were included for the years ended December 31, 2022 and 2021 as their effect was dilutive under the treasury stock method.

(2) No incremental shares of potentially dilutive restricted stock awards, restricted share units, performance share units, stock options or warrants were included for the year ended December 31, 2020, as their effect was antidilutive under the treasury stock method.

See Note 16 for discussion of the Company's share-based compensation awards.

20. Supplemental Information on Oil and Natural Gas Producing Activities (Unaudited)

The supplemental information below includes capitalized costs related to oil and natural gas producing activities; costs incurred in oil and natural gas property acquisition, exploration and development; and the results of operations for oil and natural gas producing activities. Supplemental information is also provided for oil, natural gas and NGL production and average sales prices; the estimated quantities of proved oil, natural gas and NGL reserves; the standardized measure of discounted future net cash flows associated with proved oil, natural gas and NGL reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil, natural gas and NGL reserves.

Capitalized Costs Related to Oil and Natural Gas Producing Activities

The Company's capitalized costs for oil and natural gas activities consisted of the following (in thousands):

	December 31,	
	2022	2021
Oil and natural gas properties		
Proved	$ 1,507,690	$ 1,454,016
Unproved	11,516	12,255
Total oil and natural gas properties	1,519,206	1,466,271
Less accumulated depreciation, depletion and impairment	(1,380,574)	(1,373,217)
Net oil and natural gas properties capitalized costs	$ 138,632	$ 93,054

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development

Costs incurred in oil and natural gas property acquisition, exploration and development activities which have been capitalized are summarized as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Acquisitions of properties			
Proved	$ 1,431	$ 3,545	$ 3,701
Unproved	—	—	—
Exploration (1)	809	905	1,005
Development	48,399	10,045	3,563
Total cost incurred	$ 50,639	$ 14,495	$ 8,269

(1) Includes land, geological, geophysical and leasehold costs.

Results of Operations for Oil and Natural Gas Producing Activities

The following table presents the Company's results of operations from oil and natural gas producing activities (in thousands), which exclude any interest costs or indirect general and administrative costs and, therefore, are not necessarily indicative of the impact the Company's operations have on actual net earnings.

	Year Ended December 31,		
	2022	2021	2020
Revenues	$ 254,258	$ 168,882	$ 114,450
Expenses			
Production costs	57,221	46,309	53,474
Depreciation and depletion	11,542	9,372	50,349
Impairment	—	—	218,399
Total expenses	68,763	55,681	322,222
Income (loss) before income taxes	185,495	113,201	(207,772)
Income tax expense (benefit) (1)	45,055	26,734	(51,750)
Results of operations for oil and natural gas producing activities (excluding corporate overhead and interest costs)	$ 140,440	$ 86,467	$ (156,022)

(1) Income tax (benefit) expense is hypothetical and is calculated by applying the Company's statutory tax rate to (loss) income before income taxes attributable to our oil and natural gas producing activities, after giving effect to permanent differences and tax credits.

Oil, Natural Gas and NGL Reserve Quantities

Proved oil, natural gas and NGL reserves are those quantities, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, based on oil, natural gas and NGL prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

The term "reasonable certainty" implies a high degree of confidence that the quantities of oil, natural gas and NGLs actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the Company's engineers and independent petroleum consultants relied on technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used to estimate the Company's proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the reserve estimates is dependent on many factors, including the following:

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

Proved developed reserves are proved reserves 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 with the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively large major expenditure is required for recompletion.

Approximately 95% of the Company's proved reserves estimates have been prepared by independent reservoir engineers and geoscience professionals and the remaining 5% of proved reserves are estimated internally are reviewed by members of the Company's senior management to ensure that the Company consistently applies rigorous professional standards and the reserve definitions prescribed by the SEC.

Cawley, Gillespie & Associates, independent oil and natural gas consultants, prepared the estimates of proved reserves of oil, natural gas and NGLs for approximately 95% of the Company's net interest in oil and natural gas properties as of the years ended December 31, 2022 and 2021. Cawley, Gillespie & Associates are independent petroleum engineers, geologists, geophysicists and petrophysicists and do not own an interest in the Company or its properties and are not employed on a contingent basis. The remaining proved reserves were based on Company estimates.

The Company believes the geoscience and engineering data examined provides reasonable assurance that the proved reserves are economically producible in future years from known reservoirs, and under recent, past or historical economic conditions, operating methods and governmental regulations. Estimates of proved reserves are subject to change, either positively or negatively, as additional information is available and contractual and economic conditions change.

2022 Activity. Proved reserves increased from 71.3 MMBoe at December 31, 2021 to 74.3 MMBoe at December 31, 2022, primarily as a result of positive revisions of 9.1 MMBoe associated with the increase in year-end SEC commodity prices for oil and natural gas, 1.8 MMBoe related to the Company's well reactivation program, and 1.0 MMBoe associated with other commercial improvements. Further, extensions added 1.2 MMBoe and purchases added 0.2 MMBoe of proved reserves. These increases were offset by 2022 production totaling 6.5 MMBoe, a decrease of 1.0 MMBoe due to higher operating expenses in the trailing twelve month period used in the projections, and a decrease of 2.8 MMBoe attributable to other revisions.

2021 Activity. Proved reserves increased from 36.9 MMBoe at December 31, 2020 to 71.3 MMBoe at December 31, 2021, primarily as a result of positive revisions of 27.3 MMBoe associated with the increase in year-end SEC commodity prices for oil and natural gas, 13.6 MMBoe associated with reduction in expenses and other commercial improvements, 3.7 MMBoe related to a well reactivation program, and purchases of 1.4 MMBoe of proved reserves. The Company also recorded 2021 production totaling 6.8 MMBoe and a decrease of 3.6 MMBoe due to sales and 1.2 MMBoe attributable to well shut-ins, and other revisions.

2020 Activity. Proved reserves decreased from 89.9 MMBoe at December 31, 2019 to 36.9 MMBoe at December 31, 2020, primarily as a result of downward revisions of 45.0 MMBoe associated with the decrease in year-end SEC commodity prices for oil and natural gas consisting of (27.8 MMBoe from removing PUDs, and 17.3 MMBoe from remaining proved reserves). The Company also recorded 2020 production totaling 8.7 MMBoe and a decrease of 9.0 MMBoe attributable to well shut-ins, sales and other revisions. These reductions were partially offset by an 8.6 MMBoe increase associated with reduction in expenses and other commercial improvements, and purchases of 1.1 MMBoe of proved reserves.

The summary below presents changes in the Company's estimated reserves. NPB is included in 2021, 2020 and 2019.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf) (1)	Total MBoe
Proved developed and undeveloped reserves				
As of December 31, 2019	35,308	15,859	232,307	89,885
Revisions of previous estimates (2)	(24,650)	(2,246)	(107,426)	(44,800)
Acquisitions of new reserves	74	437	3,391	1,076
Sales of reserves in place	(163)	(111)	(1,827)	(579)
Production	(2,084)	(2,694)	(23,552)	(8,703)
As of December 31, 2020	8,485	11,245	102,893	36,879
Revisions of previous estimates (2)	3,627	14,924	148,736	43,340
Acquisitions of new reserves	135	438	5,235	1,446
Sales of reserves in place	(3,440)	(28)	(716)	(3,587)
Production	(957)	(2,266)	(21,417)	(6,793)
As of December 31, 2021	7,850	24,313	234,731	71,285
Revisions of previous estimates (2)	971	2,825	25,841	8,102
Acquisitions of new reserves	39	65	528	192
Extensions and discoveries	510	227	2,823	1,208
Production	(949)	(1,997)	(21,101)	(6,463)
As of December 31, 2022	8,421	25,433	242,822	74,324
Proved developed reserves				
As of December 31, 2019	14,078	14,532	200,853	62,086
As of December 31, 2020	8,485	11,245	102,893	36,879
As of December 31, 2021	7,850	24,313	234,731	71,285
As of December 31, 2022	8,421	25,433	242,822	74,324
Proved undeveloped reserves				
As of December 31, 2019	21,230	1,327	31,454	27,799
As of December 31, 2020	—	—	—	—
As of December 31, 2021	—	—	—	—
As of December 31, 2022	—	—	—	—

(1) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.
(2) Revisions include changes due to previous quantity estimates, pricing, productions costs, and other commercial factors.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year to year are prepared in accordance with ASC Topic 932, Extractive Activities—Oil and Gas, ("ASC Topic 932"). The assumptions underlying the computation of the standardized measure of discounted cash flows may be summarized as follows:

- the standardized measure includes the Company's estimate of proved oil, natural gas and NGL reserves and projected future production volumes based upon economic conditions;
- pricing is applied based upon SEC prices at December 31, 2022, 2021 and 2020, adjusted for fixed or determinable contracts that are in existence at year-end.

The calculated weighted average per unit prices for the Company's proved reserves and future net revenues were as follows:

	At December 31, 2022	At December 31, 2021	At December 31, 2020
Oil (per Bbl)	$ 93.73	$ 64.95	$ 36.54
NGL (per Bbl)	$ 33.42	$ 19.26	$ 6.40
Natural gas (per Mcf)	$ 4.76	$ 2.56	$ 0.87

- future development and production costs are determined based on trailing 12 month average cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

The summary below presents the Company's future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure in ASC Topic 932 (in thousands).

	December 31, 2022	December 31, 2021	December 31, 2020
Future cash inflows from production	$ 2,795,762	$ 1,579,734	$ 471,038
Future production costs (1)	(1,131,145)	(735,904)	(270,512)
Future development costs (2)	(36,730)	(66,732)	(81,687)
Future income tax expenses (3)	(17,780)	—	—
Undiscounted future net cash flows	1,610,107	777,098	118,839
10% annual discount	(803,242)	(344,184)	(13,853)
Standardized measure of discounted future net cash flows (4)	$ 806,865	$ 432,914	$ 104,986

(1) Consists of severance taxes, ad valorem taxes, and lease operating expenses.
(2) Includes abandonment costs.
(3) The future income tax expenses have been computed using statutory tax rates, giving effect to allowable tax deductions and tax credits under current laws, including expected tax benefits to be realized from the utilization of net operating loss carryforwards.
(4) NPB is included in 2020.

The following table represents the Company's estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Beginning present value	$ 432,914	$ 104,986	$ 364,290
Changes during the year			
Revenues less production	(197,419)	(122,964)	(61,407)
Net changes in prices, production and other costs	465,116	380,026	(135,652)
Development costs incurred	846	83	—
Net changes in future development costs (1)	3,028	446	(2,167)
Extensions and discoveries	36,984	—	—
Revisions of previous quantity estimates (1)	98,579	112,926	(99,533)
Accretion of discount	34,138	6,016	36,429
Net change in income taxes	(3,798)	—	—
Purchases of reserves in-place	3,039	15,541	4,744
Sales of reserves in-place	—	(29,792)	(1,067)
Timing differences and other (2)	(66,562)	(34,354)	(651)
Net change for the year	373,951	327,928	(259,304)
Ending present value (3) (4)	$ 806,865	$ 432,914	$ 104,986

(1) The change in estimated future development costs and revisions of previous quantity estimates primarily reflect increases from the well reactivation program as a result of more producing wells and extended reserve life due to increase in pricing.

(2) The change in timing differences and other are related to revisions in the Company's estimated time of production and development.

(3) Standardized Measure was determined using SEC prices, and does not reflect actual prices received or current market prices.

(4) NPB is included in 2020.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

Not applicable.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures.

Under the supervision and with the participation of the Company's management, including its Chief Executive Officer and Chief Financial Officer, the Company performed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(b) and 15d-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the Company's Chief Executive Officer and its Chief Financial Officer concluded that its disclosure controls and procedures were effective as of December 31, 2022 to provide reasonable assurance that the information required to be disclosed by the Company in its reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

The information required to be filed pursuant to this item is set forth under the captions "Management's Report on Internal Control over Financial Reporting" in Item 8 of this report.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. ***Other Information***

Not applicable.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

Not applicable.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2023: "Director Biographical Information," "Executive Officers," "Compliance with Section 16(a) of the Exchange Act" and "Corporate Governance Matters."

Item 11. *Executive Compensation*

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2023: "Director Compensation," "Outstanding Equity Awards" and "Executive Officers and Compensation."

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

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2023: "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management."

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

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2023: "Related Party Transactions" and "Corporate Governance Matters."

Item 14. *Principal Accounting Fees and Services*

The information required by this item is incorporated herein by reference to the section captioned "Ratification of Selection of Independent Registered Public Accounting Firm" in the Company's definitive proxy statement, which will be filed no later than April 30, 2023.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

The following documents are filed as a part of this report:

1. *Consolidated Financial Statements*

Reference is made to the Index to Consolidated Financial Statements appearing on page 55.

2. *Financial Statement Schedules*

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

3. *Exhibits*

EXHIBIT INDEX

		Incorporated by Reference				
Exhibit No.	**Exhibit Description**	**Form**	**SEC File No.**	**Exhibit**	**Filing Date**	**Filed Herewith**
2.1	Amended Joint Chapter 11 Plan of Reorganization of SandRidge Energy, Inc., et al., dated September 19, 2016	8-A	001-33784	2.1	10/4/2016	
3.1	Amended and Restated Certificate of Incorporation of SandRidge Energy, Inc.	8-A	001-33784	3.1	10/4/2016	
3.2	Amended and Restated Bylaws of SandRidge Energy, Inc.	8-A	001-33784	3.2	10/4/2016	
3.3	Certificate of Designations of Series B Participating Preferred Stock of SandRidge Energy, Inc.	8-K	001-33784	3.1	11/27/2017	
3.4	Certificate of Designation of Series A Junior Participating Preferred Stock of SandRidge Energy, Inc., as filed with the Secretary of State of Delaware	8-A	001-33784	3.1	7/2/2020	
4.1	Form of specimen Common Stock certificate of SandRidge Energy, Inc.	8-K	001-33784	4.1	10/7/2016	
4.2	Warrant Agreement, dated as of October 4, 2016, between SandRidge Energy, Inc. and American Stock Transfer & Trust Company, LLC, as warrant agent	8-K	001-33784	10.6	10/7/2016	
4.3	Registration Rights Agreement dated as of October 4, 2016, among SandRidge Energy, Inc. and the holders party thereto	8-A	001-33784	10.1	10/4/2016	
4.4	Stockholder Rights Agreement, dated as of November 26, 2017, between SandRidge Energy, Inc. as the Company, and American Stock Transfer & Trust Company, LLC as Rights Agent	8-K	001-33784	4.1	11/27/2017	
4.5	First Amendment to Stockholder Rights Agreement, dated as of January 22, 2018, by and between SandRidge Energy, Inc. and American Stock Transfer & Trust Company, LLC, as Rights Agent	8-K	001-33784	4.1	1/23/2018	
4.6	Description of Registrant's Securities	10-K	001-33784	4.6	2/27/2020	*
10.1†	SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	8-K	001-33784	10.8	10/7/2016	
10.1.1†	Form of Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.1.4	3/3/2017	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith
10.1.1.1†	Form of Amendment No. 1 to the Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.4.1	11/3/2017	
10.1.2†	Form of Performance Share Unit Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.1.5	3/3/2017	
10.1.3†	Form of Non-employee Director Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.6	8/7/2017	
10.1.3.1†	Form of Amendment No. 1 to the Non-employee Director Restricted Stock Award Certificate and Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.6.1	11/3/2017	
10.1.4†	Form of Restricted Stock Award Certificate and Agreement (Double Trigger) for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.1.7	2/22/2018	
10.1.5†	Form of Non-employee Director Restricted Stock Award Agreement for SandRidge Energy, Inc. 2016 Omnibus Incentive Plan, dated July 17, 2018	10-Q	001-33784	10.1.1	11/8/2018	
10.2†	Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan, dated August 8, 2018	10-Q	001-33784	10.1	11/8/2018	
10.2.1†	Form of Executive Restricted Stock Award Agreement for Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.2	11/8/2018	
10.2.2†	Form of Performance Share Unit Award Agreement for Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-Q	001-33784	10.1.3	11/8/2018	
10.2.3†	Form of Option Award Agreement for Amended and Restated SandRidge Energy, Inc. 2016 Omnibus Incentive Plan	10-K	001-33784	10.2.3	3/4/2019	
10.3†	2015 Form of Employment Agreement for Executive Vice Presidents and Senior Vice Presidents of SandRidge Energy, Inc.	10-Q	001-33784	10.3.4	11/5/2015	
10.4†	The SandRidge Energy, Inc. Special Severance Plan	10-Q	001-33784	10.3.7	5/09/2019	
10.4.1†	First Amendment to the SandRidge Energy, Inc. Special Severance Plan	10-Q	001-33784	10.3.8	5/09/2019	
10.4.2†	Second Amendment to the SandRidge Energy, Inc. Special Severance Plan	10-K	001-33784	10.4.2	2/27/2020	
10.5†	Form of Indemnification Agreement for directors and officers	8-K	001-33784	10.9	10/7/2016	
10.6	Amended and Restated Credit Agreement, dated as of June 21, 2019, among SandRidge Energy, Inc., Royal Bank of Canada, as Administrative Agent, and the other lenders party thereto filed as Exhibit A to the Refinancing Amendment No. 2 to the Existing Credit Agreement	8-K	001-33784	10.1	6/27/2019	
10.7	Pledge and Security Agreement, dated as of October 4, 2016, by SandRidge Energy, Inc., the other grantors party thereto, and Royal Bank of Canada, as Administrative Agent	10-K	001-33784	10.6	3/3/2017	
10.8	Intercreditor and Subordination Agreement, dated as of October 4, 2016, among SandRidge Energy, Inc., Royal Bank of Canada, as priority lien agent, and Wilmington Trust, National Association, as the subordinated collateral trustee	8-K	001-33784	10.4	10/7/2016	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith
10.9	Collateral Trust Agreement, dated as of October 4, 2016, among SandRidge Energy, Inc., the guarantors from time to time party thereto, Wilmington Trust, National Association, as Trustee under the Indenture, the other Parity Lien Representatives from time to time party thereto and Wilmington Trust, National Association, as Collateral Trustee	8-K	001-33784	10.5	10/7/2016	
10.10.1	Settlement Agreement, dated June 19, 2018, by and among SandRidge Energy, Inc., Carl C. Icahn, Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Enterprises G.P. Inc., Icahn Enterprises Holdings L.P., IPH GP LLC, Icahn Capital L.P., Icahn Onshore LP, Icahn Offshore LP, Beckton Corp., High River Limited Partnership, Hopper Investments LLC and Barberry Corp. and Bob Alexander, Sylvia K. Barnes, Jonathan Christodoro, William M. Griffin, Jr., John "Jack" Lipinski and Randolph Read	8-K	001-33784	10.1	6/19/2018	
10.10.2	Confidentiality Agreement, dated June 22, 2018, by and among SandRidge Energy, Inc., Carl C. Icahn, High River Limited Partnership, Hopper Investments LLC, Barberry Corp., Icahn Partners LP, Icahn Partners Master Fund LP, Icahn Enterprises G.P. Inc., Icahn Enterprises Holdings L.P., IPH GP LLC, Icahn Capital LP, Icahn Onshore LP, Icahn Offshore LP, Beckton Corp, Jesse Lynn and Louie Pastor	8-K	001-33784	10.2	6/19/2018	
10.13	Real Estate Purchase and Sale Agreement, dated May 15, 2020, by and between Robinson Park, LLC and SandRidge Realty LLC	8-K	001-33784	10.1	5/19/2020	
10.14	Tax Benefits Preservation Plan, dated July 1, 2020, between SandRidge Energy, Inc. and American Stock Transfer & Trust Company, LLC as Rights Agent	8-K	001-33784	4.1	7/2/2020	
10.15	Letter Agreement, dated April 24, 2020, by and between the Company and Salah Gamoudi	8-K	001-33784	10.1	7/2/2020	
10.16	Purchase and Sale Agreement by and between SandRidge Energy, Inc. and Gondola Resources, LLC, dated December 11, 2020	8-K	001-33784	2.1	12/14/2020	
10.17	Stock Options Award Agreement - Grayson Pranin					*
10.18	Restricted Stock Units Award Agreement - Grayson Pranin					*
21.1	Subsidiaries of SandRidge Energy, Inc.					*
22.1	Subsidiary Guarantors and Issuers of Guaranteed Securities	10-K	001-33784	22.1	3/4/2021	
23.1	Consent of Moss Adams LLP					*
23.2	Consent of Deloitte & Touche LLP					*
23.3	Consent of Cawley, Gillespie & Associates					*
23.4	Consent of Ryder Scott Company, L.P.					*
31.1	Section 302 Certification-Chief Executive Officer					*
31.2	Section 302 Certification-Chief Financial Officer					*
32.1	Section 906 Certifications of Chief Executive Officer and Chief Financial Officer					*
99.1	Report of Cawley, Gillespie & Associates					*
99.2	Schedule II - Valuation and Qualifying Accounts					*

Exhibit No.	Exhibit Description	Incorporated by Reference: Form	SEC File No.	Exhibit	Filing Date	Filed Herewith
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.					*
101.SCH	XBRL Taxonomy Extension Schema Document					*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					*
101.DEF	XBRL Taxonomy Extension Definition Document					*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					*

† Management contract or compensatory plan or arrangement

Item 16. ***Form 10-K Summary***

Not Applicable.

SIGNATURES

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

SANDRIDGE ENERGY, INC.

By /s/ Grayson Pranin

Grayson Pranin

President, Chief Executive Officer and Chief Operating Officer

March 15, 2023

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Grayson Pranin and Salah Gamoudi and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully 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/ GRAYSON PRANIN **Grayson Pranin**	President, Chief Executive Officer and Chief Operating Officer (Principal Executive Officer)	March 15, 2023
/s/ SALAH GAMOUDI **Salah Gamoudi**	Executive Vice President, Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer)	March 15, 2023
/s/ JONATHAN FRATES **Jonathan Frates**	Chairman	March 15, 2023
/s/ NANCY DUNLAP **Nancy Dunlap**	Director	March 15, 2023
/s/ JAFFREY FIRESTONE **Jaffrey Firestone**	Director	March 15, 2023
/s/ JOHN J. LIPINSKI **John J. Lipinski**	Director	March 15, 2023
/s/ RANDOLPH C. READ **Randolph C. Read**	Director	March 15, 2023