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

Form 10-K

☒ **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**

Commission file number: 001-35371

CIVITAS

Civitas Resources, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**61-1630631**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification number)
555 17th Street, Suite 3700	
Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

(303) 293-9100
(Registrant's telephone number, including area code)

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

(Title of Class)	(Trading Symbol)	(Name of Exchange)
Common Stock, par value $0.01 per share	CIVI	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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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. 7262(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 Act). Yes ☐ No ☒

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates on June 30, 2022, based upon the closing price of $52.29 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $2.7 billion. Excludes approximately 33.5 million shares of the registrant's common stock held by executive officers, directors, and stockholders that the registrant has concluded, solely for the purpose of the foregoing calculation, were affiliates of the registrant.

Number of shares of registrant's common stock outstanding as of February 20, 2023: 80,209,865

Documents Incorporated By Reference:

Portions of the registrant's definitive proxy statement, will be filed with the Securities and Exchange Commission within 120 days of December 31, 2022, as incorporated by reference into Part III of this report for the year ended December 31, 2022.

CIVITAS RESOURCES, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2022

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Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains various statements, including those that express belief, expectation, or intention, as well as those that are not statements of historic fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"). When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project," "plan," "will," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements include statements related to, among other things:

- the Company's business strategies;
- reserves estimates;
- estimated sales volumes;
- the amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- our ability to modify future capital expenditures;
- anticipated costs;
- compliance with debt covenants;
- our ability to fund and satisfy obligations related to ongoing operations;
- compliance with government regulations, including those related to climate change as well as environmental, health, and safety regulations and liabilities thereunder;
- our ability to achieve, reach, or otherwise meet initiatives, plans, or ambitions with respect to environmental, social and governance matters;
- the adequacy of gathering systems and continuous improvement of such gathering systems;
- the impact from the lack of available gathering systems and processing facilities in certain areas;
- oil, natural gas, and natural gas liquid prices and factors affecting the volatility of such prices;
- the impact of commodity prices;
- sufficiency of impairments;
- the ability to use derivative instruments to manage commodity price risk and ability to use such instruments in the future;
- our drilling inventory and drilling intentions;
- the impact of potentially disruptive technologies;
- our estimated revenue gains and losses;
- the timing and success of specific projects;
- our implementation of standard and long reach laterals;
- our intention to continue to optimize enhanced completion techniques and well design changes;
- stated working interest percentages;
- our management and technical team;
- outcomes and effects of litigation, claims, and disputes;
- our ability to replace oil and natural gas reserves;
- our ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking;
- our ability to pay future cash dividends on our common stock;

- the impact of the loss of a single customer or any purchaser of our products;
- the timing and ability to meet certain volume commitments related to purchase and transportation agreements;
- the impact of any pandemic or other public health epidemic, including the COVID-19 pandemic;
- the impact of customary royalty interests, overriding royalty interests, obligations incident to operating agreements, liens for current taxes, and other industry-related constraints;
- our anticipated financial position, including our cash flow and liquidity;
- the adequacy of our insurance;
- the results, effects, benefits, and synergies of mergers and acquisitions; and
- other statements concerning our anticipated operations, economic performance, and financial condition.

We have based these forward-looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions, and expected future developments as well as other factors we believe are appropriate under the circumstances. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. The actual results or developments anticipated by these forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences. Actual results could differ materially from those expressed or implied in the forward-looking statements.

Factors that could cause actual results to differ materially include, but are not limited to, the following:

- the risk factors discussed in Part I, Item 1A of this Annual Report on Form 10-K;
- declines or volatility in the prices we receive for our oil, natural gas, and natural gas liquids;
- general economic conditions, whether internationally, nationally, or in the regional and local market areas in which we do business, including any future economic downturn, the impact of continued or further inflation, disruption in the financial markets, and the availability of credit on acceptable terms;
- the effects of disruption of our operations or excess supply of oil and natural gas due to world health events, including the COVID-19 pandemic, and the actions by certain oil and natural gas producing countries, including Russia;
- the ability of our customers to meet their obligations to us;
- our access to capital on acceptable terms;
- our ability to generate sufficient cash flow from operations, borrowings, or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future sales volume rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves;
- the possibility that the industry may be subject to future local, state, and federal regulatory or legislative actions (including additional taxes and changes in environmental regulation and regulations addressing climate change);
- environmental risks;
- seasonal weather conditions as well as severe weather and other natural events caused by climate change;
- lease stipulations;
- drilling and operating risks, including the risks associated with the employment of horizontal drilling and completion techniques;
- our ability to acquire adequate supplies of water for drilling and completion operations;
- availability of oilfield equipment, services, and personnel;
- exploration and development risks;
- operational interruption of centralized oil and natural gas processing facilities;
- competition in the oil and natural gas industry;

- management's ability to execute our plans to meet our goals;
- our ability to attract and retain key members of our senior management and key technical employees;
- our ability to maintain effective internal controls;
- access to adequate gathering systems and pipeline take-away capacity;
- our ability to secure adequate processing capacity for natural gas we produce, to secure adequate transportation for oil, natural gas, and natural gas liquids we produce, and to sell the oil, natural gas, and natural gas liquids at market prices;
- costs and other risks associated with perfecting title for mineral rights in some of our properties;
- political conditions in or affecting other producing countries, including conflicts in or relating to the Middle East, South America, and Russia (including the current events involving Russia and Ukraine), and other sustained military campaigns or acts of terrorism or sabotage;
- the continuing effects of the COVID-19 pandemic, including any recurrence or the worsening thereof; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical, and technological factors that may negatively impact our businesses, operations, or pricing.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions, and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions, or expectations will be achieved. We disclose other important factors that could cause our actual results to differ materially from our expectations under *Item 1A. Risk Factors* and *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

GLOSSARY OF OIL AND NATURAL GAS TERMS

We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

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

"Analogous reservoir." Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

"Asset Sale." Any direct or indirect sale, lease (including by means of production payments and reserve sales and a sale and lease-back transaction), transfer, issuance, or other disposition, or a series of related sales, leases, transfers, issuances, or dispositions that are part of a common plan, of (a) shares of capital stock of a subsidiary, (b) all or substantially all of the assets of any division or line of business of the Company or any subsidiary, or (c) any other assets of the Company or any subsidiary outside of the ordinary course of business.

"Basin." A large natural depression on the earth's surface in which sediments are generally deposited.

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

"Bcf." One billion cubic feet of natural gas.

"Boe." One stock tank barrel of oil equivalent, calculated by converting natural gas volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

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

"CIG." Colorado Interstate Gas index.

"Completion." The process of stimulating a drilled well followed by the installation of permanent equipment to allow for the production of crude oil and/or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Condensate." A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

"Deterministic method." The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

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

"Development costs." Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and 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 and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and 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 vapor recovery systems.

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

"Differential." The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead price received.

"Dry hole." Exploratory or development well that does not produce oil or gas in commercial quantities.

"Economically producible." The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the cash costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities.

"Estimated ultimate recovery (EUR)." Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

"Exploratory well." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well.

"Extension well." A well drilled to extend the limits of a known reservoir.

"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, laterally by local geologic barriers, or by 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.

"Formation." A layer of rock which has distinct characteristics that differ from nearby rock.

"GAAP." Generally accepted accounting principles in the United States.

"Gross Wells." The total wells in which an entity owns a working interest.

"HH." Henry Hub index.

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

"Hydraulic fracturing." The process of injecting water, proppant, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production into the wellbore.

"LOE." Lease operating expense.

"MBbl." One thousand barrels of oil or other liquid hydrocarbons.

"MBoe." One thousand Boe.

"Mcf." One thousand cubic feet.

"MMBoe." One million Boe.

"MMBtu." One million British Thermal Units.

"MMcf." One million cubic feet.

"Net acres." The percentage of total acres an owner has out of a particular number of acres or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"Net production." Production that is owned by the registrant and produced to its interest, less royalties and production due others.

"Net revenue interest." Economic interest remaining after deducting all royalty interests, overriding royalty interests, and other burdens from the working interest ownership.

"Net well." Deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells expressed as whole numbers and fractions of whole numbers.

"NGL." Natural gas liquid.

"NYMEX." The New York Mercantile Exchange.

"Oil and gas producing activities." Defined as (i) the search for crude oil, including condensate and natural gas liquids, or natural gas in their natural states and original locations; (ii) the acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties; (iii) the construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as lifting the oil and gas to the surface and gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and (iv) extraction of salable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coal beds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

"PDNP." Proved developed non-producing reserves.

"PDP." Proved developed producing reserves.

"Percentage-of-proceeds." A processing contract where the processor receives a percentage of the sold outlet stream, dry gas, NGLs, or a combination from the mineral owner in exchange for providing the processing services.

"Play." A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

"Plugging and abandonment." The sealing off of all gas and liquids in the strata penetrated by a well so that the gas and liquids from one stratum will not escape into another stratum or to the surface.

"Pooling." Pooling, either contractually or statutorily through regulatory actions, allows an operator to combine multiple leased tracts to create a governmental spacing unit for one or more productive formations. Pooling is also known as unitization or communitization. Ownership interests are calculated within the pooling/spacing unit according to the net acreage contributed by each tract within the pooling/spacing unit.

"Possible reserves." Those additional reserves that are less certain to be recovered than probable reserves.

"Present value of future net revenues or (PV-10)." A non-GAAP financial measure that represents the estimated present value from cash flows associated with proved crude oil and natural gas reserves using the preceding twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices (after adjustment for differentials in location and quality), less future development and production costs, discounted at 10% per annum.

"Probable reserves." Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"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. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are (a) costs of labor to operate the wells and related equipment and facilities; (b) repairs and maintenance; (c) materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities; (d) property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and (e) severance taxes. Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development, or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the costs of oil and gas produced along with production (lifting) costs identified above.

"Productive well." An exploratory, development, or extension well that is not a dry well.

"Proppant." Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"Proved developed reserves." Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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

(i) The area of the reservoir considered as proved includes:

  (a) The area identified by drilling and limited by fluid contacts, if any, and

  (b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

(b) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

"Reasonable certainty." If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to EUR with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"*Reclamation."* The process to restore the land and other resources to their original state prior to the effects of oil and gas development.

"Recompletion." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

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

"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible crude 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 NGLs produced and sold unencumbered by expenses of drilling, completing, and operating of the well.

"Sales volumes." All volumes for which a reporting entity is entitled to proceeds, including production, net to the reporting entity's interest and third party production obtained from percentage-of-proceeds contracts and sold by the reporting entity.

"Service well." A service well is drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

"Spacing." Spacing as it relates to a spacing unit is defined by the governing authority having jurisdiction to designate the size in acreage of a productive reservoir along with the appropriate well density for the designated spacing unit size. Typical spacing for conventional wells is 40 acres for oil wells and 640 acres for gas wells. Typical spacing for unconventional wells is either 640 acres or 1,280 acres for both oil and gas. However, spacing units continue to increase in size as longer lateral length wells are becoming more common in the basin in which we operate.

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

"Undeveloped reserves." Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped oil and gas reserves."

"Working interest." The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"Workover." Operations on a producing well to restore or increase production.

"WTI." West Texas Intermediate index.

PART I

Item 1. *Business*

When we use the terms "Civitas," the "Company," "we," "us," or "our," we are referring to Civitas Resources, Inc. and its consolidated subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under *Glossary of Oil and Natural Gas Terms* above. Throughout this document, we make statements that may be classified as "forward-looking." Please refer to the *Information Regarding Forward-Looking Statements* section above for an explanation of these types of statements.

Overview

Civitas is an independent exploration and production company focused on the acquisition, development, and production of oil and associated liquids-rich natural gas in the Rocky Mountain region, primarily in the Denver-Julesburg Basin of Colorado (the "DJ Basin"). Our operations are focused on developing the horizontal Niobrara and Codell formations that have a low-cost structure, mature infrastructure, strong production efficiencies, multiple producing horizons, multiple service providers, established reserves, and prospective drilling opportunities, which help facilitate predictable production and achieve our business strategies.

As of December 31, 2022, we had approximately 525,900 net acres in the Rocky Mountain region. Approximately 470,000 net, or 89%, of the Company's acreage is located in some of the most productive areas of the DJ Basin. We believe our acreage has been significantly delineated by our own drilling success and by the success of offset operators, providing confidence that our results are repeatable and will continue to generate economic returns. As of December 31, 2022, we operated a total of 3,108 gross producing wells, of which 2,551 were horizontal. Our working and net revenue interest in our operated wells averaged approximately 80% and 65%, respectively.

We are committed to pursuing compelling economic returns and generating significant free cash flow. To that end, we strive to deliver a peer-leading operating cost structure, maximize capital efficiencies, and minimize capital reinvestment rates, while keeping production broadly flat over time. Our technical staff of geologists, petroleum engineers, and geophysicists have decades of industry experience and are experts in horizontal drilling and fracture stimulation.

We are focused on exceptional performance in managing the Environmental, Social, and Governance ("ESG") aspects of our business, with the goal of mitigating risks while benefiting our stakeholders and partnering with the communities where we operate. The Company is also actively pursuing projects designed to reduce or eliminate carbon emissions associated with its operations and then offsets remaining emissions through the retirement of certified carbon offsets and renewable energy credits. Additionally, we established the Civitas Community Foundation in 2022, and we intend to invest in a comprehensive retrofit of natural gas pneumatic devices starting in 2023.

Our Business Strategies

The Company's primary objective is to maximize shareholder returns by responsibly developing our oil and natural gas resources. To achieve this, Civitas is guided by four foundational pillars that we believe add long-term, sustainable value. These pillars are:

- *Generate free cash flow.* Our investment opportunities are evaluated primarily in the context of maximizing free cash flow. We have a high-quality asset base, allowing us to create synergies and maintain a low-cost structure. We pursue value-accretive investments to enhance our ability to deliver incremental free cash flow to our shareholders. During 2022, Civitas generated approximately $1.2 billion of free cash flow (a non-GAAP financial measure — please refer to the *Reconciliation of Free Cash Flow to Cash Provided by Operating Activities* presented in *Part II, Item 7, Non-GAAP Financial Measures* of this report).
- *Maintain a premier balance sheet.* A strong balance sheet, focus on cost control, and minimizing long-term commitments are critical to managing risk and achieving success within fluctuating market conditions. As evidenced by our strong liquidity position of approximately $1.8 billion as of December 31, 2022, as discussed in *Part II, Item 7, Liquidity and Capital Resources*, we believe Civitas has among the strongest balance sheets in the exploration and production sector.

- *Return free cash flow to shareholders.* We prioritize consistently delivering free cash flow to shareholders through our published dividend framework. During 2022, we returned more than $530 million to investors through base and variable dividends, including approximately $166 million paid in December 2022. We believe Civitas has one of the industry's highest payout ratios with an approximate 11% yield at year-end. In early 2023, we used cash-on-hand to repurchase approximately 4.9 million shares from our largest shareholder, CPPIB Crestone Peak Resources Canada Inc., further underscoring our commitment to this priority.
- *Demonstrate ESG Leadership.* We have integrated ESG initiatives throughout our organization and strive to reduce and eliminate emissions while seeking to comply with all applicable air quality and other environmental rules and regulations. We employ industry-leading best practices, including electric drilling rigs and frac spreads, 24/7 air monitoring technology and pipeline gathering and takeaway, as well as vapor recovery, automated shut-in and remote monitoring equipment for producing wells where feasible and appropriate. We believe Civitas is Colorado's first carbon neutral operator on both a Scope 1 and Scope 2 basis, meaning that Civitas is at a neutral balance between emitting and removing carbon from the atmosphere. We regularly engage community stakeholders in our development planning and operations. We strive to maintain a safe workplace for our employees and contractors at all times. During 2022, we maintained a meaningful safety track record as evidenced by a low total recordable incident rate of 0.19 as further discussed within *Human Capital* below. Finally, our Board of Directors (the "Board") also has a dedicated ESG Committee that is responsible for overseeing and supporting our commitment to environmental, health and safety, social responsibility, sustainability, and other public policy matters relevant to the Company.

Significant Developments in 2022

We successfully navigated a challenging 2022, delivering on our key financial objectives while maintaining a strong capital structure. We successfully executed our development plan and countered industry-wide inflationary pressures while exercising capital discipline to ensure we were investing in our best projects and able to return significant free cash flow to shareholders.

We posted strong financial results in 2022, including net income of approximately $1.2 billion and cash flow from operating activities of approximately $2.5 billion, driven primarily by commodity prices and well performance from our high-return development projects. We invested approximately 39% of our 2022 cash flow from operating activities into drilling and completion activities, allowing us to continue to return significant cash to shareholders through our base and variable dividend. In early 2022, the Board initiated a quarterly variable cash dividend in addition to our base dividend. We believe Civitas provides investors with one of the highest dividend yields in the exploration and production sector.

The Company achieved its annual safety target, advanced critical environmental, health, and safety objectives, integrated data management systems to improve productivity and aligned work processes, and continued to cultivate a results-driven employee culture focused on continuous improvement. Additionally, we safely tested enhanced completion designs on large, efficient multi-well pads throughout the Company's acreage position. Fluid volumes and types, fluid rates, proppant volumes and types, stage spacing, perforation architecture, lateral spacing, and flowback techniques were the primary variables that were tested throughout the 2022 program. Along with extensive internal evaluation, the Company will also continue to monitor industry trends, public data, and information from non-operated wells to further optimize completion techniques.

During 2022, the Company incurred capital costs of approximately $988.5 million that, along with the incremental production acquired through acquisitions, drove an increase in sales volumes to 170.0 MBoe per day. The capital invested during 2022 allowed the Company to drill 176, complete 142, and turn to sales 146 gross operated wells.

The following table summarizes our estimated proved reserves as of December 31, 2022:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed	117,768	750,793	102,004	344,904
Undeveloped	34,834	116,707	16,830	71,115
Total Proved	152,602	867,500	118,834	416,019

Total proved reserves as of December 31, 2022 increased by approximately 5% from December 31, 2021.

The following table summarizes our PV-10 reserve value, sales volumes, and proved undeveloped drilling locations as of December 31, 2022:

Estimated Proved Reserves at December 31, 2022[1]			Average Net Daily Sales Volumes for the Year Ended December 31, 2022	Gross Proved Undeveloped Drilling Locations as of December 31, 2022
Total Proved (MBoe)	**% Proved Developed**	**PV-10 ($ in MM)[2]**	**(Boe/d)**	
416,019	83 %	$ 9,834.3	170,035	201

(1) Proved reserves and PV-10[2] were calculated using the preceding twelve-month unweighted arithmetic average of the first-day-of-the-month price ("SEC prices"), which were $93.67 per Bbl WTI and $6.36 per MMBtu HH. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $3.39 per Bbl for crude oil and a decrease of $1.32 per MMBtu for natural gas assuming an average Btu factor of 1.1 MMBtu/Mcf.

(2) PV-10 is a non-GAAP financial measure. Please refer to the *Reconciliation of Proved Reserves PV-10 to Standardized Measure* presented in *Part II, Item 7, Non-GAAP Financial Measures* of this report.

Our Operations

Our operations are located in the Rocky Mountain region, primarily in the DJ Basin, and target the Niobrara and Codell formations. As of December 31, 2022, our total acreage position consisted of approximately 826,500 gross (525,900 net) acres, and our estimated proved reserves were 416,019 MBoe and contributed 170.0 MBoe per day of sales volumes during 2022. We believe our position allows us to control the pace, costs, and completion techniques used in the development of our reserves.

As of December 31, 2022, we had working interests in a total of 3,702 gross producing wells, of which 3,116 were horizontal. Our working and net revenue interest for all wells in which we had a working interest averaged approximately 69% and 56%, respectively. Our sales volumes for the fourth quarter of 2022 were 169.4 MBoe per day.

We drilled 176 gross (152.0 net) wells in 2022. As of December 31, 2022, we have identified approximately 201 gross (141.7 net) proved undeveloped drilling locations on our acreage.

Reserves

Estimated Proved Reserves

The summary data with respect to our estimated proved reserves presented below has been prepared in accordance with rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to companies involved in oil and natural gas producing activities. Our reserve estimates do not include probable or possible reserves. Our estimated proved reserves for the years ended December 31, 2022, 2021, and 2020 were determined using SEC prices. For a definition of proved reserves under the SEC rules, please see the *Glossary of Oil and Natural Gas Terms* included in the beginning of this report.

Reserve estimates are inherently imprecise and estimates for undeveloped properties are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, all of these estimates are expected to change as new information becomes available. Neither prices nor costs have been escalated. The actual quantities and present values of our estimated proved reserves may vary from what we have estimated.

The table below sets forth information regarding our estimated proved reserves, nearly all of which are located in the Rocky Mountain region, primarily in the DJ Basin, as of December 31, 2022, 2021, and 2020. The proved reserve estimates as of December 31, 2022, 2021, and 2020 were prepared by third-party independent reserve engineers Ryder Scott Company, LP. ("Ryder Scott"). For more information regarding Ryder Scott, please see *Independent Reserve Engineers* below. The information in the following table is not intended to represent the current market value of our proved reserves nor does it reflect current or expected commodity price realizations.

	As of December 31,		
	2022	2021	2020
Reserve Data[(1)]:			
Estimated proved reserves:			
Oil (MMBbls)	152.6	143.6	52.8
Natural gas (Bcf)	867.5	888.5	235.7
Natural gas liquids (MMBbls)	118.8	106.0	26.1
Total estimated proved reserves (MMBoe)[(2)]	416.0	397.7	118.2
Percent oil and liquids	65 %	63 %	67 %
Estimated proved developed reserves:			
Oil (MMBbls)	117.8	104.1	24.3
Natural gas (Bcf)	750.8	748.8	123.2
Natural gas liquids (MMBbls)	102.0	89.0	14.3
Total estimated proved developed reserves (MMBoe)[(2)]	344.9	317.8	59.2
Percent oil and liquids	64 %	61 %	65 %
Estimated proved undeveloped reserves:			
Oil (MMBbls)	34.8	39.5	28.5
Natural gas (Bcf)	116.7	139.7	112.5
Natural gas liquids (MMBbls)	16.8	17.1	11.8
Total estimated proved undeveloped reserves (MMBoe)[(2)]	71.1	79.9	59.0
Percent oil and liquids	73 %	71 %	68 %

(1) Proved reserves were calculated using SEC prices, which were $93.67 per Bbl WTI and $6.36 per MMBtu HH, $66.56 per Bbl WTI and $3.60 per MMBtu HH, and $39.57 per Bbl WTI and $1.99 per MMBtu HH for the years ended December 31, 2022, 2021, and 2020, respectively. Adjustments were made for location and grade.

(2) Determined using the ratio of 6 Mcf of natural gas to one Bbl of crude oil.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are 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. Proved undeveloped 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 productivity at greater distances.

Proved undeveloped locations in our December 31, 2022 reserve report are included in our development plan and are scheduled to be drilled within five years from the year they were initially recorded, consistent with the SEC's five-year rule requirement. Annually, management creates a capital expenditure plan based on our best available data at the time the plan is developed. The development plan is based upon management's evaluation of a number of qualitative and quantitative factors including estimated risk-based returns, estimated well density, commodity prices and cost forecasts, recent drilling results and well performance, and anticipated availability of services, equipment, supplies, and personnel. Generally, the Company books proved undeveloped locations within one development spacing area from developed producing locations. For the instances where a proved undeveloped location is beyond one spacing area from a developed producing location, the Company utilizes reliable geologic and engineering technology inclusive of, but not limited to, pressure performance, geologic mapping, offset productivity, electric logs, seismic, and production data.

As of December 31, 2022, we had 201 gross proved undeveloped locations compared to 234 as of December 31, 2021. The Company's gross proved undeveloped drilling locations as of December 31, 2022 have an average lateral length of approximately 2.2 miles.

Total estimated proved reserves at December 31, 2022 increased 18.3 MMBoe, or 5%, to 416.0 MMBoe when compared to December 31, 2021. A summary of the Company's changes in quantities of proved reserves for the year ended December 31, 2022 is as follows:

	Net Reserves (MBoe)
Beginning of year	397,690
Production	(62,063)
Purchases of minerals in place	27,269
Extensions, discoveries, and other additions	27,904
Removed from capital program	(228)
Revisions to previous estimates	25,447
End of year	416,019

The 27.3 MMBoe of purchases of minerals in place is comprised of 22.5 MMBoe and 4.8 MMBoe from the Bison Acquisition and acquisition of additional working interest in Company-operated wells, respectively. The 27.9 MMBoe of extensions, discoveries, and other additions were primarily attributable to the success observed in our horizontal drilling program that resulted in the addition of 21.6 MMBoe through 61 proved undeveloped location additions and 6.3 MMBoe of new proved developed reserves that did not have any associated proved undeveloped reserves recorded as of December 31, 2021. The positive revision of proved reserves as compared to previous estimates is 25.4 MMBoe. Price-related revisions of 11.8 MMBoe resulted from the increase to SEC prices of $27.11 to $93.67 per Bbl WTI for oil and $2.76 to $6.36 per MMBtu HH for natural gas. The remaining positive revisions of 13.6 MMBoe are primarily driven by updates to well performance forecasts and NGL yields.

Proved Undeveloped Reserves

	Net Reserves (MBoe)
Beginning of year	79,851
Converted to proved developed	(43,995)
Purchases of minerals in place	12,420
Additions from capital program	21,578
Removed from capital program	(228)
Revisions to previous estimates	1,489
End of year	71,115

As of December 31, 2022, our proved undeveloped reserves were 71.1 MMBoe, nearly all of which are scheduled to be drilled within three years from the year they were initially recorded, well within the SEC's five-year rule requirement. We recognize proved undeveloped reserves on undrilled acreage directly offsetting development areas that are reasonably certain of economic producibility and regulatory accessibility, and that align with the Company's approved development plans. During 2022, the Company converted 55% of its proved undeveloped reserves, which is comprised of 107 gross wells representing net reserves of 44.0 MMBoe, at a cost of $527.5 million. The 12.4 MMBoe of purchases of minerals in place is primarily due to the Bison Acquisition. During the year, we added 61 proved undeveloped locations for a total reserve addition of 21.6 MMBoe. Increases in SEC pricing year-over-year resulted in a positive pricing revision of 1.5 MMBoe.

Internal controls over reserves estimation process

Our policies regarding internal controls over the recording of reserves estimates require reserves to be in compliance with SEC definitions and guidance and prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The Company's Audit Committee reviews significant reserve changes on an annual basis, and Ryder Scott, our third-party independent reserve engineers, is engaged by and has direct access to the Audit Committee. The reserves estimates shown herein have been independently prepared by Ryder Scott for the years ended December 31, 2022, 2021, and 2020. These reserve estimates are reviewed by our in-house technical person who oversees and controls preparation of the reserve report data by working with Ryder Scott to ensure the integrity, accuracy, and timeliness of data furnished for their evaluation process. The Company's technical person who was primarily responsible for overseeing the preparation of our reserve estimates is our Senior Manager, Reserves, who has 35 years of experience in the oil and gas industry, including 6 years in her role at the Company. Her professional qualifications include a bachelor's degree in Mathematics and Computer Science from the Colorado School of Mines.

Independent Reserve Engineers

The reserves estimates shown herein for December 31, 2022, 2021, and 2020 have been prepared by Ryder Scott. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott performs consulting petroleum engineering services under Texas Board of Professional Engineers and Land Surveyors firm registration number F-1580. Within Ryder Scott, the technical person primarily responsible for preparing the estimates set forth in the Ryder Scott reserves report filed as Exhibit 99.1 to this report is Mr. Scott James Wilson. Mr. Wilson is a licensed Professional Engineer in the State of Colorado (No. 36112) who has over 35 years of experience in the oil and gas industry and has been practicing consulting petroleum engineering at Ryder Scott since 2000. He graduated from Colorado School of Mines in 1983 with a Bachelor of Science in Petroleum Engineering and from the University of Colorado in 1985 with a Master of Business Administration. The responsible party meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Production, Revenues, and Price History

Oil and natural gas prices fluctuated significantly during 2021 and 2022. Oil and natural gas prices are impacted by production levels, inventory levels, real or perceived geopolitical risks in producing regions, the relative strength of the U.S. dollar, weather, and global demand. We reevaluate our development plan based on oil and natural gas prices, however, the Company strategy is focused on maximizing free cash flow while maintaining broadly flat production.

Sensitivity Analysis

If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 1% and our PV-10 value as of December 31, 2022 would decrease by approximately 13% or $1.3 billion. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 1% and our PV-10 value as of December 31, 2022 would increase by approximately 13% or $1.3 billion.

Production

The following table sets forth information regarding oil, natural gas, and natural gas liquids production, sales prices, and production costs for the periods indicated. For additional information, please see information set forth in *Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

	For the Year Ended December 31,		
	2022	2021	2020
Oil:			
Production (MBbls)	27,650	9,385	5,019
Average sales price (per Bbl), including derivatives[1]	$ 79.17	$ 42.49	$ 44.41
Average sales price (per Bbl), excluding derivatives[1]	$ 91.70	$ 65.41	$ 34.42
Natural Gas:			
Production (MMcf)	112,478	36,763	14,166
Average sales price (per Mcf), including derivatives[2]	$ 4.47	$ 2.43	$ 1.40
Average sales price (per Mcf), excluding derivatives[2]	$ 6.15	$ 3.84	$ 1.45
Natural Gas Liquids:			
Production (MBbls)	15,666	4,934	1,858
Average sales price (per Bbl), including derivatives	$ 33.14	$ 32.84	$ 10.39
Average sales price (per Bbl), excluding derivatives	$ 35.76	$ 34.68	$ 10.39
Oil Equivalents:			
Production (MBoe)	62,063	20,445	9,239
Average Daily Production (Boe/d)	170,035	56,015	25,242
Average Production Costs (per Boe)[3]	$ 3.25	$ 3.41	$ 4.00

(1) Crude oil sales exclude $0.6 million, $1.0 million, and $1.7 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2022, 2021, and 2020, respectively.
(2) Natural gas sales exclude $3.2 million, $3.6 million, and $3.7 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2022, 2021, and 2020, respectively.
(3) Represents lease operating expense and midstream operating expense per Boe using total production volumes and excludes ad valorem and severance taxes.

Customers

We believe the loss of any one customer would not have a material effect on our financial position or results of operations because there are numerous potential customers for our product. In 2022, the Company had three customers that represented a combined total of 72% of the Company's revenue; Customer A accounted for 50% of revenue, Customer B accounted for 12% of revenue, and Customer C accounted for 10% of revenue.

Delivery Commitments

The Company is party to a number of agreements containing minimum volume commitments that require us to deliver fixed determinable quantities of oil, natural gas, and NGLs. Under the terms of these agreements, the Company is required to make periodic deficiency payments for any shortfalls in delivering minimum gross volume commitments. Please refer to *Part II, Item 8, Note 6 - Commitments and Contingencies* for additional discussion.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned a working interest at December 31, 2022.

	Oil		Natural Gas		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	3,633	2,488	69	48	3,702	2,536	3,108	2,476

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2022. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary.

	Developed Acres[(1)]		Undeveloped Acres[(2)]		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
DJ Basin	526,600	396,900	172,200	73,100	698,800	470,000
Other Rocky Mountain	107,800	42,600	19,900	13,300	127,700	55,900
Total	634,400	439,500	192,100	86,400	826,500	525,900

(1) Developed acreage is acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease.
(2) Undeveloped acreage is acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Certain leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. Approximately 29,200 net acres, or 5.6%, of the Company's total net acres may expire in the next three years if production is not established or if we do not extend lease terms. We intend to extend our strategic leases to the extent possible. Decisions to let leasehold expire generally relate to areas outside of our core area of development or when the expirations do not pose material impacts to development plans or reserves. The following table sets forth the undeveloped acreage, as of December 31, 2022, that will expire in the years indicated unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	Expiring 2023		Expiring 2024		Expiring 2025		Expiring 2026 and Beyond	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain	33,200	17,600	4,900	4,900	10,700	6,700	13,100	6,900

Drilling Activity

The following table sets forth the operated development well activity for the periods presented. Development wells consist of wells completed and/or turned to sales during the period, regardless of when drilling was initiated.

	Year Ended December 31,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Development wells completed	142	125.2	100	86.2	9	8.5
Development wells turned to sales	146	129.5	70	61.5	26	23.1

The following table presents our in-process wells as of December 31, 2022. In-process wells represent wells that are in the process of being drilled or have been drilled and are waiting to be completed and/or for pipeline connection.

	As of December 31, 2022	
	Gross	Net
In-process development wells	108	91.5

There were no exploratory drilling activities during the years ended December 31, 2022, 2021, and 2020. Additionally, we did not have any dry wells during the same periods.

Derivative Activity

In addition to supply and demand, oil, natural gas, and NGL prices are affected by seasonal, economic, local, and geo-political factors that we can neither control nor predict. We attempt to mitigate a portion of our exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows through the use of derivative contracts. As of December 31, 2022, the Company had entered into the following commodity price derivative contracts:

	Contract Period				
	Q1 2023	Q2 2023	Q3 2023	Q4 2023	2024
Oil Derivatives (volumes in Bbl/day and prices in $/Bbls)					
Swaps					
NYMEX WTI Volumes	1,320	1,205	1,053	984	1,019
Weighted-Average Contract Price	$ 74.29	$ 73.49	$ 70.92	$ 70.61	$ 66.78
Two-Way Collars					
NYMEX WTI Volumes	1,054	—	—	—	—
Weighted-Average Ceiling Price	$ 72.70	$ —	$ —	$ —	$ —
Weighted-Average Floor Price	$ 40.00	$ —	$ —	$ —	$ —
Three-Way Collars					
NYMEX WTI Volumes	1,721	1,436	1,302	1,172	143
Weighted-Average Ceiling Price	$ 58.75	$ 57.69	$ 57.48	$ 56.49	$ 56.25
Weighted-Average Floor Price	$ 49.31	$ 48.10	$ 47.91	$ 49.04	$ 45.00
Weighted-Average Sold Put Price	$ 39.25	$ 37.70	$ 37.41	$ 39.04	$ 35.00
Natural Gas Derivatives (volumes in MMBtu/day and prices in $/MMBtu)					
Swaps					
NYMEX HH Volumes	47,368	46,374	46,120	45,947	24,148
Weighted-Average Contract Price	$ 2.65	$ 2.64	$ 2.61	$ 2.60	$ 2.70
Two-Way Collars					
NYMEX HH Volumes	9,558	1,563	1,887	1,756	1,033
Weighted-Average Ceiling Price	$ 3.23	$ 2.78	$ 2.96	$ 2.96	$ 3.05
Weighted-Average Floor Price	$ 2.03	$ 2.21	$ 2.34	$ 2.38	$ 2.38
Three-Way Collars					
NYMEX HH Volumes	899	505	—	—	303
Weighted-Average Ceiling Price	$ 3.19	$ 3.33	$ —	$ —	$ 3.49
Weighted-Average Floor Price	$ 2.50	$ 2.50	$ —	$ —	$ 2.50
Weighted-Average Sold Put Price	$ 2.00	$ 2.00	$ —	$ —	$ 2.00

Subsequent to December 31, 2022, the Company entered into a series of fixed price, natural gas basis protection swaps on all of its outstanding NYMEX HH positions through the third quarter of 2024 to mitigate exposure to adverse pricing differentials between NYMEX HH and CIG. The weighted-average contract price entered of $(0.13) per MMBtu represents the amount of reduction to the NYMEX HH natural gas price for the contracted volumes covered by the basis protection swaps.

Title to Properties

Our properties are subject to customary royalty interests, overriding royalty interests, obligations incident to operating and joint venture agreements, liens for current taxes, other industry-related constraints, and certain other leasehold restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business. We believe that we have satisfactory title to all of our producing properties. Although title to our properties is subject to complex interpretation of multiple conveyances, deeds, reservations, and other instruments that serve to affect mineral title, we believe that none of these risks will materially detract from the value of our properties or from our interest therein or otherwise materially interfere with the operation of our business.

Competition

The oil and natural gas industry is highly competitive, and we compete with a substantial number of other companies that often have greater resources. Many of these companies explore for, produce, and market oil and natural gas, carry on refining operations, and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, attracting and retaining qualified personnel, and obtaining transportation for the oil and natural gas we produce. There is also competition between producers of oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state, and local governments; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing, or producing oil and natural gas and may prevent or delay the commencement or continuation of certain operations. The effect and potential impacts of these risks are difficult to accurately predict.

Further, oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 65% of our estimated proved reserves as of December 31, 2022 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. During the year ended December 31, 2022, the daily NYMEX WTI oil spot price ranged from a high of $123.64 per Bbl to a low of $71.05 per Bbl, and the NYMEX natural gas HH spot price ranged from a high of $9.85 per MMBtu to a low of $3.46 per MMBtu.

Insurance Matters

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business, either because such insurance is not available or customary, or because premium costs are considered cost-prohibitive. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations, or cash flows.

Regulation of the Oil and Natural Gas Industry

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

Failure to comply with applicable laws and regulations can result in substantial penalties and the suspension or cessation of operations. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations. The regulatory burden on the industry can increase the cost of doing business and negatively affect profitability. Because such laws and regulations are frequently revised and amended through various legislative actions and rulemakings, it is difficult to predict the future costs or impact of compliance. Additional rulemakings that affect the oil and natural gas industry are regularly considered at the federal, state, and various local government levels, including statutorily and through powers granted to various agencies that regulate our industry, and various court actions. We cannot predict when or whether any such future rulemakings may become effective or if the outcomes will negatively affect our operations.

We believe that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows, or results of operations. However, it is difficult to estimate the potential impact on our business from rules and regulations adopted by, and potential future rulemakings of, the Colorado Oil and Gas Conservation Commission ("COGCC") in November 2020 pursuant to Colorado Senate Bill 19-181, discussed herein, which impose a number of new and amended requirements on our operations. These requirements, and any new requirements, could make it more difficult and costly to develop new oil and natural gas wells and to continue to produce existing wells, increase our costs of compliance and doing business, and delay or prevent development in certain areas or under certain conditions. We cannot assure that the existing rules, as implemented, or any future rulemaking, will not have a material and adverse impact on our financial position, cash flows, or results of operations. In addition, the current regulatory requirements may change, currently unforeseen incidents may occur, or past noncompliance with laws or regulations may be discovered, any of which could likewise have a material adverse effect on our financial position, cash flows, or results of operations.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state, and federal statutes, rules, orders, and regulations. Federal, state, and local statutes and regulations require, among other things, permits for drilling operations, drilling bonds, and reports concerning operations. Colorado, the state in which we own and operate the vast majority of our properties, has regulations governing conservation matters, including provisions for the spacing and unitization or pooling of oil and natural gas properties, the regulation of well spacing and well density, and procedures for proper plugging and abandonment of wells and associated facilities. These regulations effectively identify well densities by geologic formation and the appropriate spacing and pooling unit size to effectively drain the resources. Operators can apply for exceptions to such regulations, including applications to increase well densities to more effectively recover the oil and gas resources. Moreover, Colorado imposes a production or severance tax with respect to the production and sale of oil, natural gas, and natural gas liquids within its jurisdiction.

Colorado also regulates drilling and operating activities by requiring, among other things, permits for new pad locations, the drilling of wells, best management practices and/or conditions of approval for operating wells, maintaining bonding requirements in order to drill or operate wells, regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Colorado laws also govern a number of environmental, health and safety matters that may impact our drilling and operating activities, including setbacks from buildings, schools, and other occupied areas, sensitive habitats and/or disproportionately impacted communities, consideration of alternative locations for new wells, the handling and disposal of waste materials, prevention of venting and flaring, mitigation of noise, lighting, visual, odor, and dust impacts, air pollutant emissions permitting, protection of certain wildlife habitat, protection of public health, safety, welfare, and environment, and evaluation of cumulative impacts.

Regulation of transportation of oil

Our sales of crude oil are affected by the availability, terms, and cost of transportation. Interstate transportation of oil by pipeline is regulated by FERC pursuant to the Interstate Commerce Act ("ICA"), the Energy Policy Act of 1992, and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products (collectively referred to as "petroleum pipelines"), be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC.

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

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act ("NGPA") and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act ("NGA"), and by regulations and orders promulgated by FERC under the NGA. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

FERC issued a series of orders in 1996 and 1997 to implement its open access policies. As a result, the interstate pipelines' traditional role as wholesalers of natural gas has been greatly reduced and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

The Domenici Barton Energy Policy Act of 2005 ("EP Act of 2005") introduced significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC. The EP Act of 2005 provided FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increased FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day, with such penalties adjusted regularly for inflation. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. FERC's anti-manipulation rule, adopted pursuant to EP Act of 2005, makes it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation more accessible to natural gas services subject to the jurisdiction of FERC, for any entity, directly or indirectly, (1) to use or employ any device, scheme, or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering. However, it does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases, or transportation subject to FERC jurisdiction. The anti-manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Our sales of natural gas are also subject to requirements under the Commodity Exchange Act ("CEA"), and regulations promulgated thereunder by the Commodity Futures Trading Commission ("CFTC"). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although its policy continues to evolve, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts, or Congress.

State regulation of natural gas gathering facilities generally includes various safety, environmental, and, in some circumstances, nondiscriminatory-take requirements. Although nondiscriminatory-take regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

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

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines. Changes in law and to FERC and state utility commission policies and regulations also may result in increased regulation of our business and operations, and we cannot predict what future action FERC or any state utility commission will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers, and marketers with which we compete.

Regulation of derivatives

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") was passed by Congress and signed into law in July 2010. The Dodd-Frank Act is designed to provide a comprehensive framework for the regulation of the over-the-counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd-Frank Act subjects swap dealers and major swap participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users.

Environmental, Health and Safety Regulation

Our natural gas and oil exploration and production operations are subject to numerous stringent federal, state, and local laws and regulations governing public and occupational safety and health, the discharge of hazardous materials into the environment, or otherwise relating to protection of the environment or natural resources, noncompliance with which can result in substantial administrative, civil, and criminal penalties and other sanctions, including suspension or cessation of operations. These laws and regulations may, among other things, require the acquisition of permits and other approvals before drilling or other regulated activity commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment; require the assessment and mitigation of potential surface impacts; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities that have certain impacts or that occur in certain areas; require some form of investigation or remedial action to prevent or mitigate pollution from former and ongoing legacy operations such as plugging low-producing wells or restrictions from using earthen pits; establish specific safety and health criteria addressing worker, public health, and natural resource protection, and impose substantial liabilities or curtail operations for unpermitted pollutant emissions or failure to comply with regulatory filing obligations. Cumulatively, these laws and regulations may impact our operations.

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

Air emissions

The Clean Air Act ("CAA") and comparable state and local laws and regulations restrict the emission of air pollutants from many sources, including oil and gas operations, and impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification and operation of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining required air permits can significantly delay the development of certain oil and natural gas projects. Over the next several years, we may be required to incur certain expenditures for air pollution control equipment or other air emissions-related issues.

Federal Air Regulation

In June 2016, the U.S. Environmental Protection Agency (the "EPA") finalized additional New Source Performance Standards ("NSPS") rules, known as Subpart OOOOa, focused on achieving additional methane and volatile organic compound reductions from new and modified oil and natural gas production and natural gas processing and transmission facilities. Among other things, these revisions imposed new requirements for leak detection and repair, control requirements for oil well completions, and additional control requirements for gathering, boosting, and compressor stations. In September 2020, the EPA finalized two sets of amendments to the 2016 OOOOa standards. The first, known as the "2020 Technical Rule" reduced the 2016 rule's fugitive emissions monitoring requirements and expanded exceptions to pneumatic pump requirements, among other changes. The second, known as the "2020 Policy Rule" rescinded the methane specific requirements for certain oil, NGL and natural gas sources in the production and processing segments. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the 2020 Technical Rule by September 2021 and consider revising the 2020 Policy Rule. In June 2021, President Biden signed a Congressional Review Act ("CRA") resolution passed by Congress that revoked the 2020 Policy Rule. The CRA did not address the 2020 Technical Rule. Further, on November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule would establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. On November 15, 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters." The EPA is expected to issue a final rule by August 2023.

In October 2015, the EPA finalized its rule lowering the earlier 75 part per billion ("ppb") national ambient air quality standards ("2008 NAAQS") for ozone under the CAA to 70 ppb ("2015 NAAQS"). The state of Colorado's Denver Metro and North Front Range ("DM/NFR") air quality control region has been unable to attain the 2008 and 2015 ozone NAAQS since their adoption, and received a bump-up in its existing non-attainment status for the 2008 NAAQS from "serious" to "severe" in 2022 due to violations at area monitors during the 2020 ozone season. A "severe" classification would trigger significant additional obligations under the CAA and state laws and will result in new and more stringent air quality control requirements applicable to our operations and significant operating costs and delays in obtaining necessary permits for new and modified production facilities. Among other requirements, a "severe" classification for the 2008 NAAQS may require additional permitting in the nonattainment area for any source with the potential to emit more than 25 tons per year of volatile organic compounds or nitrogen oxides. Additionally, the DM/NFR's non-attainment boundary for the 2015 NAAQS was successfully challenged by environmental groups and local governments seeking to expand the boundary to include all of northern Weld County in the case of *Clean Wisconsin v. EPA*, No. 18-1203, in which the D.C. Circuit remanded the boundary determination to the EPA for further support or re-designation. In response, the EPA chose to re-designate the boundary for the 2015 ozone NAAQS to include all of Weld County, which action became effective on December 30, 2021. Weld County has challenged the EPA's action upon remand in the D.C. Circuit, and the case is pending and is not likely to be decided until early 2023. *Bd. of County Comm. of Weld County v. EPA*, No. 21-1263.

State Air Regulation

In February 2014, the Colorado Department of Public Health and Environment's Air Quality Control Commission ("AQCC") adopted new and revised air quality regulations that imposed stringent new requirements to control emissions from both existing and new or modified oil and gas facilities in Colorado. The regulations included new emissions control, monitoring, recordkeeping, and reporting requirements, as well as a Leak Detection and Repair ("LDAR") program for well production facilities and compressor stations. The LDAR program primarily targets hydrocarbon (i.e., methane) emissions from the oil and gas sector in Colorado.

The AQCC has adopted new and revised air quality regulations that extended the controls adopted in 2014 to many lower producing and emitting facilities statewide, and added storage tank loadout controls to those requirements, among other changes. The new rules also increased the frequency of LDAR monitoring to semi-annual for lower producing facilities previously subject to a one-time monitoring requirement, as well as monthly LDAR monitoring for facilities within 1,000 feet of occupied areas, and imposed a new emission inventory and reporting of greenhouse gases ("GHGs"), among other requirements. The AQCC also revised rules specific to the oil and gas sector in September 2020, and again in December 2020; these revisions included emission control requirements for natural gas fired engines typically in compression service, for pre-production tanks used in flowback, and also established a preproduction air monitoring plan requirement for operators for the first time, as well as further revisions to LDAR monitoring requirements within 1,000 feet of occupied areas.

In 2021, the AQCC also adopted regulations requiring the use of non-emitting pneumatic controllers at both new and existing facilities, increasing LDAR monitoring frequencies, requiring additional pneumatic controller emissions reduction and elimination requirements, imposing enclosed combustion device testing requirements, and requiring company-wide GHG intensity reductions, among other things. These updated regulations are aimed in substantial part at achieving GHG and conventional pollutant emission reductions from Colorado's oil and gas industry in response to legislative directives, including Colorado House Bill 19-1261, which set ambitious GHG emission targets, and House Bill 21-1266, which modified those targets, among other things.

Each of the above AQCC rulemakings are intended to further Colorado's legislative directive to reduce GHG emissions to attain climate action goals. AQCC is expected to undertake several rulemaking efforts to further reduce emissions in the next several years.

Beginning in November 2020, the COGCC has adopted new regulations that generally prohibit the venting or flaring of natural gas during drilling, completion, and production operations, with limited exceptions, using its expanded oil and gas conservation and environmental protection authority under Colorado Senate Bill 19-181. Among other things, these regulations require that operators proposing new oil and gas wells either commit to connecting to a gathering system when production commences or submit a gas capture plan and significantly increase the financial assurance amounts required for oil and gas producers to cover potential cleanup costs.

Compliance with these and other air pollution control, air monitoring, gas capture, 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 costs could be significant.

Hydraulic fracturing

Regulations relating to hydraulic fracturing. We are subject to extensive federal, state, and local laws and regulations concerning public health and safety, and environmental protection. Government authorities frequently review, revise and supplement these requirements, and both oil and gas development generally, and hydraulic fracturing specifically, are receiving increasing regulatory attention. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

States have historically regulated oil and gas exploration and production activity, including hydraulic fracturing. The Colorado state government where we operate has adopted or is considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Colorado requires operators to reduce hydrocarbon emissions associated with hydraulic fracturing, prepare and report significant data regarding oil and gas impacts, compile and report additional information regarding wellbore integrity, publicly disclose the chemical ingredients used in hydraulic fracturing, maintain minimum distance between occupied structures and oil and gas wells, undertake additional mitigation for nearby residents, and implement additional groundwater testing. Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions to our operations.

The federal Safe Drinking Water Act ("SDWA") and comparable state statutes may restrict the disposal, treatment, or release of water produced or used during oil and gas development. Subsurface emplacement of fluids, primarily via disposal wells or enhanced oil recovery ("EOR") wells, is governed by federal or state regulatory authorities that, in some cases, include the state oil and gas regulatory or the state's environmental authority. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of "underground injection," but disposal of hydraulic fracturing fluids and produced water or their injection for EOR is not excluded.

Federal agencies have periodically considered additional regulation of hydraulic fracturing. The EPA has published guidance for issuing underground injection permits that would regulate hydraulic fracturing using diesel fuel. This guidance eventually could encourage other regulatory authorities to adopt permitting and other restrictions on the use of hydraulic fracturing. In June 2016, the EPA finalized regulations that address discharges of wastewater pollutants from onshore unconventional extraction facilities to publicly-owned treatment works. The EPA also published a study of the impact of hydraulic fracturing on drinking water resources, which concluded that drinking water resources can be affected by hydraulic fracturing under specific circumstances. The results of this study could result in additional regulations, which could lead to operational burdens similar to those described above. The United States Department of the Interior also finalized a rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity, and handling of flowback water; however, on December 29, 2017, the Bureau of Land Management ("BLM") rescinded the hydraulic fracturing rule. This rescission and the rule as promulgated are subject to ongoing litigation. Additionally, in 2016, the BLM finalized rules related to further controlling the venting and flaring of natural gas on BLM land, which was challenged by a group of states. On September 28, 2018, the BLM published a final rule that revised the 2016 rules, which was again challenged by states and environmental groups. On November 30, 2022, the BLM also issued a proposed rule to reduce the waste of natural gas from venting, flaring and leaks during oil and gas production activities on Federal and Indian leases. Future litigation regarding the 2016 and 2018 rules, and any alternative future rule therefore creates some uncertainty as to how BLM's regulation of venting and flaring will impact our business.

Apart from these ongoing federal and state initiatives, some state and local governments have adopted their own new requirements on hydraulic fracturing and other oil and gas operations. At the state level, interest groups in Colorado have proposed or advanced initiatives restricting or banning oil and gas development in Colorado, but these initiatives have failed to date. Further, Colorado Senate Bill 19-181 amended state law to give municipalities and counties greater local control over siting and permitting of oil and gas locations, and some municipalities within the state have implemented regulations within their jurisdictions. Any successful bans or moratoria where we operate, whether at the state or local level, could increase the costs of our operations, impact our profitability, and even prevent us from drilling in certain locations which could adversely impact our ability to develop our reserves. In addition, in light of concerns about seismic activity potentially being triggered by the injection of produced waters into underground wells, certain regulators have adopted or are considering additional requirements related to seismic safety for hydraulic fracturing activities or the underground injection of fluid wastes. For example, the regulations that the COGCC adopted in November 2020 impose various requirements on the underground injection of fluid wastes to further seismic safety and protect the environment. Any regulation that restricts our ability to dispose of produced waters or increases the cost of doing business could have a material adverse effect on our business.

At this time, it is not possible to estimate the potential impact on our business of recent state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing. The adoption of future federal, state, or local laws or implementing regulations imposing new environmental obligations on, or otherwise limiting, our operations could make it more difficult and more expensive to complete oil and natural gas wells, increase our costs of compliance and doing business, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products. We cannot assure that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations.

Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in the Rocky Mountain region.

Typical hydraulic fracturing treatments are made up of water, proppant, and certain chemical additives. We utilize major hydraulic fracturing service companies who track and report additive chemicals that are used in fracturing as required by the appropriate government agencies, including FracFocus, the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Each of the service companies we use fracture stimulate a multitude of wells for the industry each year.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. Our operations are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), who frequently inspect our fracturing operations.

Other State Laws

Our properties located in Colorado are subject to the authority of the COGCC, as well as other state agencies. Over the past several years, the COGCC has approved new rules regarding various matters, including wellbore integrity, hydraulic fracturing, well control, waste management, spill reporting, spacing of wells and pooling of mineral interests, and an increase in potential sanctions for COGCC rule violations.

In April 2019, Colorado Senate Bill 19-181 (SB 181) became effective, which substantially changes the state's regulation of oil and gas exploration and production activities. SB 181 changed the COGCC's mission from "fostering" responsible and balanced development "consistent with protection" of public health and the environment to "regulating" development "to protect" public health and the environment. SB 181 also instituted several state-wide regulatory changes, namely (i) changed the composition of the COGCC to remove two seats for industry experts and add experts on wildlife/environmental protection and public health, and changed the Commissioners' employment from volunteer to full-time positions, (ii) changed Colorado's statutory pooling provisions to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required, (iii) changed state pre-emption law such to afford local governments greater control over oil and gas siting, and (iv) initiated a comprehensive rulemaking to amend COGCC's rules consistent with the agency's revised mission.

Among the most significant changes under SB 181 was the aforementioned provision giving local governments greater control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments can inspect oil and gas operations and impose fines for leaks and spills. Regulation in the municipalities and areas where we operate could result in increased costs, delays in securing permits and other approvals related to our operations, and otherwise materially impact our ability to operate and drill new wells in the areas where we hold oil and gas interests.

The COGCC has adopted significant additional regulations to implement SB 181. The legislation mandated COGCC rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned or shut-in, financial assurance, wellbore integrity, and application fees. In November 2022, the COGCC completed rulemaking on flowlines and wells that are inactive, temporarily abandoned, or shut-in and completed rulemaking on wellbore integrity in June 2020. In January 2021, the results of a major rulemaking took effect addressing a wide range of topics including facility siting, cumulative impacts, development approvals, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection, and those rules apply to permit applications pending on or submitted after that date and generally to operations occurring on or after that date. The agency has issued certain written guidance on many of the issues addressed to provide direction on regulatory interpretation and compliance, and it may continue to issue new or revised guidance in the future. The COGCC has also issued rules on financial assurance, application fees, and high priority habitat. The financial assurance rule increased the amounts that operators are required to provide as a surety bond for assurance that wells will be properly plugged and abandoned at the end of their lifecycle. Depending on how these and any other new rules are applied and enforced, they could add substantial increases in well costs for our Colorado operations. The rules could also impact our ability to operate and extend the time necessary to obtain drilling permits, which would create substantial uncertainty about future development plans.

SB 181 also required the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds and nitrogen oxides associated with certain oil and gas facilities. The AQCC adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, and for reducing emissions from pneumatic devices, and expanded storage tank control and loadout control requirements applicable statewide in December 2019. The legislation also grants the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling, and completion.

Hazardous substances and waste handling

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that transported, disposed, or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these potentially responsible parties may be subject to strict, joint, and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as or contain CERCLA hazardous substances but we are not aware of any liabilities for which we may be held responsible that would materially or adversely affect us.

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous wastes, and distinguishes between hazardous and non-hazardous or solid wastes. With the approval of the EPA, the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent hazardous waste requirements, while all states regulate solid waste. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of natural gas and oil are currently regulated under RCRA's non-hazardous waste provisions and state solid waste laws. However, legislation has been proposed from time to time and various environmental groups have filed lawsuits that, if successful, could result in the reclassification of certain oil and natural gas exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent and costly handling, disposal, and clean-up requirements. The EPA has indicated that it will continue to work with states and other organizations to identify areas for continued improvement and to address emerging issues to ensure that exploration, development, and production wastes continue to be managed in a manner that protects human health and the environment. Environmental groups will likely continue to press the issue at the federal and state levels.

In 2018, the Colorado State legislature passed Senate Bill 245 that gave the Colorado Department of Public Health & Environment (“CDPHE”) the authority to promulgate rules for the safe management of Technologically Enhanced Naturally Occurring Radioactive Material (“TENORM”). TENORM is naturally occurring radioactive material whose radionuclide concentrations are increased through human activity, such as through generation of water treatment residuals, scales, and sediments from oil and gas production, and other processes. During 2020, CDPHE promulgated new rules governing TENORM waste, which were adopted in November 2020 and became effective January 14, 2021, but were not enforceable until July 14, 2022, to provide operators time to come into compliance. During drilling, completion, and production, numerous waste streams that may contain TENORM are created that are hauled for disposal at permitted disposal facilities. CDPHE has developed guidance documents and is holding stakeholder meetings to help impacted facility operators characterize existing materials, make a TENORM determination and comply with the new rules. Depending on the final waste streams chosen for characterization and regulatory levels set for disposal, costs for characterization, storage, and disposal of waste could significantly increase.

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

In addition, other laws require the reporting on use of hazardous and toxic chemicals. For example, the oil and gas extraction industry and natural gas processing facilities that receive and refine natural gas are required to report releases of certain “toxic chemicals” under the Toxic Release Inventory (“TRI”) program under the Emergency Planning and Community Right-to-Know Act.

Pipeline safety and maintenance

Pipelines, gathering systems, and terminal operations are subject to increasingly strict safety laws and regulations. Both the transportation and storage of refined products and crude oil involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant penalties, liability for natural resources damages, and significant business interruption. The U.S. Department of Transportation has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection, and management of our pipeline and storage facilities. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. The Pipeline Safety, Regulatory Certainty, and Job Creation Act was signed into law in early 2012. In addition, the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) has issued new rules to strengthen federal pipeline safety enforcement programs. In 2015, PHMSA proposed to expand its regulations in a number of ways, including through the increased regulation of gathering lines, even in rural areas. In 2016, PHMSA increased its regulations to require crude oil sampling and reporting as an “offeror” (as defined under the PHMSA) and increased its civil penalty structure. In November 2021, PHMSA issued its final rule extending reporting requirements to all onshore gas gathering operators and applying a set of minimum safety requirements to certain onshore gas gathering pipelines with large diameters and high operating pressures.

In Colorado, on March 17, 2021, the Public Utilities Commission adopted Regulation 11 rules Regulating Pipeline Operators and Gas Pipeline Safety. These regulations apply to all gas public utilities, all municipal or quasi-municipal corporations transporting natural gas or providing natural gas services, all operators of master meter systems, and all operators of pipelines transporting gas in intrastate commerce including gas gathering system operators (certain provisions are tailored to the location and size of the gathering systems involved). The rules require all filed reports to be publicly available and all Notices of Proposed Violation, Notices of Action, pleadings and decisions to be filed publicly. The rules also provide a revised methodology for calculating civil penalties in an effort to provide clarity to both operators and the public.

Climate change

The EPA has adopted rules requiring the monitoring and reporting of GHGs from specified onshore and offshore oil and gas production sources in the U.S. on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the EPA's GHG emissions reporting rule and Colorado's GHG emissions inventory and reporting rules more recently adopted.

In August 2022, President Biden signed into law the Inflation Reduction Act of 2022. Among other things, the Inflation Reduction Act includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a "waste emissions charge" on certain oil and gas sources that are already required to report under EPA's Greenhouse Gas Reporting Program. In addition, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of carbon taxes, policies, and incentives to encourage the use of renewable energy or alternative low-carbon fuels, and cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs.

At the international level, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, which resulted in an agreement intended to nationally determine their contributions and set GHG emission reduction goals every five years beginning in 2020. In November 2019, plans were formally announced for the U.S. to withdraw from the Paris Agreement with an effective exit date in November 2020. In February 2021, the current administration announced reentry of the U.S. into the Paris Agreement along with a new "nationally determined contribution" for U.S. GHG emissions that would achieve emissions reductions of at least 50% relative to 2005 levels by 2030. The U.S. returned to participation in the U.N. Framework Convention on Climate Change 26th Conference of the Parties ("COP26") held in Glasgow, Scotland in November 2021, advancing a Global Methane Pledge along with the European Union, which aims to cut global methane emissions at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. Since its formal launch at COP26, over 100 countries representing almost 70% of global GDP have signed. Most recently, at the 27th Conference of Parties ("COP27"), President Biden announced the EPA's proposed standards to reduce methane emissions from existing oil and gas sources, and agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement.

The $1 trillion legislative infrastructure package passed by Congress in November 2021 includes a number of climate-focused spending initiatives targeted at climate resilience, enhanced response and preparation for extreme weather events, and clean energy and transportation investments. The Inflation Reduction Act of 2022 also provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture, and other programs directed at addressing climate change.

Additionally, on March 21, 2022, the SEC issued a proposed rule regarding the enhancement and standardization of mandatory climate-related disclosures for investors. The proposed rule would require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including, but not limited to, information about the registrant's governance of climate-related risks and relevant risk management processes; climate-related risks that are reasonably likely to have a material impact on the registrant's business, results of operations, or financial condition and their actual and likely climate-related impacts on the registrant's business strategy, model, and outlook; climate-related targets, goals, and transition plan (if any); certain climate-related financial statement metrics in a note to their audited financial statements; Scope 1 and Scope 2 GHG emissions; and Scope 3 GHG emissions and intensity, if material, or if the registrant has set a GHG emissions reduction target, goal, or plan that includes Scope 3 GHG emissions. Although the proposed rule's ultimate date of effectiveness and the final form and substance of these requirements is not yet known and the ultimate scope and impact on our business is uncertain, compliance with the proposed rule, if finalized, may result in increased legal, accounting, and financial compliance costs, make some activities more difficult, time-consuming, and costly, and place strain on our personnel, systems, and resources.

On May 30, 2019, Colorado also passed GHG inventory legislation and climate action legislation. House Bill 19-1261 concerns the reduction of greenhouse gas pollution and established statewide greenhouse gas pollution reduction goals. Senate Bill 19-096 concerns the collection of greenhouse gas emissions data to facilitate measures to cost-effectively meet the states GHG emissions reduction goals established in HB 19-1261. Regulations implementing the GHG inventory requirements of these statutes took effect on July 15, 2020. Additionally, on September 30, 2020, the Colorado Energy Office and Colorado Department of Public Health and Environment finalized a Greenhouse Gas Pollution Reduction Roadmap in January 2021. The GHG Roadmap lays out a pathway to meet the state's climate action targets established in HB 19-1261, as amended by HB 21-1266.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting, emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Additional limitations on GHG emissions could adversely affect our production operations and/or demand for the oil and natural gas we produce. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could also reduce demand for the oil and natural gas we produce.

Water discharges

The Federal Water Pollution Control Act or the Clean Water Act ("CWA") and analogous state laws impose restrictions and controls regarding the discharge of pollutants into certain surface waters of the U.S., including spills and leaks of hydrocarbons and produced water. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control, and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. As properties are acquired, we determine the need for new or updated SPCC plans and, where necessary, will develop or update such plans to implement physical and operation controls, the costs of which are not expected to be material. In June 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") adopted a new regulatory definition of jurisdictional "waters of the U.S." ("WOTUS"), which never took effect before being replaced by the Navigable Waters Protection Rule in April 2020. The Navigable Waters Protection Rule was vacated by two separate federal district courts in late 2021. The EPA is undergoing a rulemaking process to redefine the definition of WOTUS which could be impacted by the U.S. Supreme Court's upcoming decision in *Sackett v. EPA*, a case regarding the proper test in determining whether wetlands qualify as WOTUS. A final rule, known as "Rule 1" was announced by the EPA and the Corps in December 2022. The EPA and Corps are expected to propose a second rule, known as "Rule 2", further refining Rule 1 by November 2023 and issue a final rule by July 2024.

In May 2020, a federal court in Montana enjoined the use of nationwide permit ("NWP") 12 to construct new oil and gas-related pipelines, on the basis that the Corps had not properly consulted with the U.S. Fish and Wildlife Service when that permit was renewed in 2017 but the U.S. Supreme Court significantly narrowed the Montana court's injunction to cover only the challenged XL Pipeline in July 2020.

In January 2021, the Corps issued proposals to revise and reissue all 52 current NWPs, including No. 12, to, among other things, lessen the burden on the energy industry and address the flaws alleged in the Montana lawsuit. The new NWPs became effective in March 2021.

Among other things, NWP 12 was broken up into three separate parts, with the new NWP 12 being limited solely to construction and maintenance of oil and gas pipelines, with other utility-related structures covered by two new NWPs. The new 2021 version of NWP 12 has again been challenged in the District of Montana, by the same plaintiffs on the same grounds, which case is still pending. On March 28, 2022, the Corps published a notice announcing that it is undertaking formal review of NWP 12 and sought public comments. The comment period ended on May 27, 2022 and the review remains pending. Any further changes to NWP 12 could have an impact on our business.

The WOTUS regulations under the current administration could ultimately change the scope of the CWA's jurisdiction and result in increased costs and delays with respect to obtaining permits for discharges of pollutants or dredge and fill activities in waters of the U.S., including regulated wetland areas.

Endangered Species Act and Migratory Bird Treaty Act

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered and threatened species or their habitats. In August 2019, the U.S. Fish and Wildlife Service (the "FWS") and National Marine Fisheries Service ("NMFS") issued three rules amending implementation of the ESA regulations revising, among other things, the process for listing species and designating critical habitat. In June and July 2022, the FWS and the NMFS issued final rules rescinding Trump-era regulations concerning the definition of "habitat" and critical habitat exclusions. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act ("MBTA"), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. On January 7, 2021, the Department of the Interior finalized a rule limiting application of the MBTA, however the Department of the Interior under President Biden delayed the effective date of the rule and opened a public comment period for further review. The January 2021 rule was revoked and replaced by a final rule on October 4, 2021. With this revocation of the January 2021 rule, the U.S. Fish and Wildlife Service returned to implementing the MBTA as prohibiting incidental take and applying enforcement discretion, consistent with long-standing agency practice prior to 2017. Concurrently, the FWS finalized a rule limiting application of the MBTA. The FWS revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment to the Department of the Interior's plan to develop regulations that authorize incidental take under certain prescribed conditions. The notice of proposed rulemaking is expected in March 2023 and is expected to be finalized by the end of 2023. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

We 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, the purpose of which are to protect the health and safety of workers. In addition, OSHA's hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations, and that this information be provided to employees, state and local government authorities, and citizens.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major federal actions having the potential to significantly impact the human environment. In the course of such evaluations, an agency will evaluate the potential direct, indirect, and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a detailed environmental impact statement that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. The vast majority of our exploration and production activities are not on federal lands. This environmental review process has the potential to delay or limit, or increase the cost of, the development of natural gas and oil projects on federal lands. Authorizations under NEPA also are subject to protest, appeal, or litigation, which can delay or halt projects. On July 16, 2020, the Council on Environmental Quality ("CEQ") revised NEPA's implementing regulations to make the NEPA process more efficient, effective, and timely. The rule required federal agencies to develop procedures consistent with the new rule within one year of the rule's effective date (which was extended to two years in June 2021). These regulations are subject to ongoing litigation in several federal district courts, and in October 2021, CEQ issued a notice of proposed rulemaking to amend the NEPA regulatory changes adopted in 2020 in two phases. Phase I of the CEQ's proposed rulemaking process was finalized on April 20, 2022, and generally restored provisions that were in effect prior to 2020. It is anticipated that Phase II of the proposed rulemaking will propose further revisions to ensure the NEPA process "provides for efficient and effective environmental reviews," and meets environmental, environmental justice, and climate change objectives. The CEQ's proposed changes could result in increased NEPA review timelines for projects involving agency action regarding federal lands, federal money, or federal permits or approvals.

Oil Pollution Act

The Oil Pollution Act of 1990 (“OPA”) establishes strict liability for owners and operators of facilities that release oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A “responsible party” under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction, or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

Human Capital

As of December 31, 2022, the Company had 353 full-time employees. We are not party to any collective bargaining agreements and have not experienced any strikes or work stoppages. Our employees play a critical role in the achievement of our short-term and long-term business goals. Consequently, we are committed to attracting, retaining and developing highly motivated and qualified employees who share our core values of sustainability, safety, innovation, integrity, and community. All employees are responsible for upholding Company-wide standards and values. We have policies designed to promote ethical conduct and integrity that employees are required to review on an annual basis. Employees are consistently provided training opportunities to develop skills in leadership, safety, and technical acumen, which help strengthen our efforts in conducting business with high ethical standards.

Our team of diverse and talented employees possess a vast array of skills including engineering, geology, research and development, midstream operations, production, logistics and administrative support, accounting, information technology, legal, policy, human resources, and finance. Certain of our employees have highly specialized skills and subject-matter expertise in their respective fields.

Health and Safety

We are committed to protecting the safety of our employees, our contractors, and the communities in which we operate. Safety is embedded in everything we do and is prioritized in each decision made by management, employees, and contractors. A commonly used measure of an organization’s safety performance is total recordable incident rate (“TRIR”), which represents the number of injuries requiring medical treatment per 100 full-time employees during a one-year period. We monitor this performance measure and communicate it broadly across the company as a means to evaluate safety performance. We are committed to maintaining a TRIR below 0.25 for both employees and contractors, a target far below industry average as reported by the Bureau of Labor Statistics for the Oil and Gas Extraction industry. During 2022, we achieved a TRIR of 0.19.

We work to identify and track hazards in the workplace and incidents so corrective actions may be taken to continuously improve safety performance. We operate our worksites under a stop work authority program, under which every person is empowered to halt operations if they observe operations that are being planned or executed without a complete risk assessment or safety management.

All employees are required to participate in training courses that ensure work is completed safely and efficiently. The courses vary according to employee group, job responsibilities, and manager discretion. Classroom training courses are held throughout the year to inform employees of relevant safety and environmental topics within the industry and to proactively ensure compliance and adherence related to recently issued rules and regulations.

Compensation, Benefits, and Employee Development

We seek to provide fair, market-competitive, performance-based compensation, and comprehensive benefits to our employees. To ensure alignment with our short-term and long-term business goals, our compensation program consists of base pay as well as short-term and long-term incentives. To foster the health and well-being of our employees and their families, all full-time employees are offered access to financial, health, and wellness programs, including: a 401(k) plan with company match, medical, dental, and vision insurance, income protection and disability coverage, paid time off, fitness reimbursement, and various quality of life tools and resources included within our Employee Assistance Program. We believe that our compensation and benefits package promotes retention and employee engagement as well as fosters physical, mental, financial, and social health within our workforce. The Compensation Committee of our Board of Directors oversees our compensation programs and regularly modifies program design to incentivize achievement of our corporate strategy and matters of importance to our stakeholders.

We recognize and support the growth of our employees by offering internal and external development programs, including a tuition reimbursement program. We invest in leadership training and professional development programs that will enable our employees to reach their potential and perform at their best.

Diversity and Inclusion

We believe a diverse and inclusive workforce is critical to our success as a business and will allow the company to gain valuable perspectives for continuous improvement. We are committed to creating and maintaining a workplace in which all employees have an opportunity to participate and contribute to the success of the business and are valued for their expertise, experiences, and ideas. The Company requires annual unconscious bias training for all employees to continue to foster an inclusive environment where everyone, regardless of background or demographic, feels valued in the workplace. Civitas provides equal opportunity for all candidates, employees, and consultants regardless of race, religion, gender, sexual orientation, age, ethnic or national origin, social origin, disability, family status, or any other protected status and personal characteristics for all aspects of employment.

We have committed to ensuring the composition of the Board of Directors includes a mix of gender and racial diversity of at least 30%, and we are proud to have already met this goal. Approximately 22% of our total workforce are women, and 15% are members of a minority group, as defined by the U.S. Equal Employment Opportunity Commission, as of December 31, 2022. As of the same date, 43% of our executives (as defined as persons at the level of Vice President and higher) are women, and 7% are members of a minority group.

Offices

As of December 31, 2022, we leased office space in Denver, Colorado at 555 17th Street where our principal offices are located. Additionally, we own and lease various field offices in Colorado.

Available Information

We are required to file annual, quarterly, and current reports, proxy statements and other information with the SEC. Our filings with the SEC are available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "CIVI." Our reports, proxy statements, and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://civitasresources.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

Item 1A. *Risk Factors.*

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition, or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Summary of the Risk Factors We Face:

- Declines in oil, natural gas, and NGL prices will adversely affect our business, financial condition or results of operations, and our ability to meet our capital expenditure obligations or targets and financial commitments.
- Our production is not fully hedged, and we may hedge a lower percentage of our production than we have in the past. We are therefore exposed to fluctuations in the price of oil, natural gas, and NGLs and will be affected by continuing and prolonged declines in such prices.
- Our derivative activities could result in financial losses or could reduce our income.
- The agreements covering our debt have restrictive covenants that could limit our ability to finance our operations, fund capital needs, respond to changing conditions, and engage in other business activities that may be in our best interests.
- Borrowings under the Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.
- Our development and production projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves or anticipated production volumes.
- Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition, or results of operations.
- Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- Continuing or worsening inflationary pressures and associated changes in monetary policy may result in increases to the cost of our goods, services, and personnel, which in turn could cause our capital expenditures and operating costs to rise.
- We intend to pursue the further development of our properties in the DJ Basin through horizontal drilling and completion. Horizontal development operations can be more operationally challenging and costly relative to our historic vertical drilling operations.
- We may be unable to make attractive acquisitions, and any inability to do so may disrupt our business.
- We may not realize anticipated benefits from mergers and acquisitions.
- Concentration of our operations in one core area may increase our risk of production loss.
- We face increasing risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in Colorado and elsewhere.
- The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.
- Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.
- Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.
- Unless we replace our oil and natural gas reserves, our reserves and production will decline, which could adversely affect our business, financial condition, and results of operations.

- We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks, including those related to our hydraulic fracturing operations.
- We are subject to health, safety, and environmental laws and regulations that may expose us to significant costs and liabilities.
- Evolving legislation or regulatory initiatives, including those related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.
- Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.
- Transition risks related to climate change, including negative shift in investor sentiment with respect to the oil and gas industry, could have material and adverse effects on us.
- We are exposed to credit risks of our hedging counterparties, third parties participating in our wells, and our customers.
- We may be involved in legal cases that may result in substantial liabilities.
- We are subject to federal, state, and local taxes and may become subject to new taxes, and certain federal income tax deductions and state income tax deductions and exemptions currently available with respect to oil and gas exploration and development may be eliminated or reduced as a result of future legislation.
- Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.
- The HighPoint, Extraction, and the Crestone Peak Mergers triggered a limitation on the utilization of our historic U.S. net operating loss carryforwards (“NOLs”), HighPoint’s NOLs, Extraction’s NOLs, and Crestone Peak’s NOLs.
- The COVID-19 pandemic has had, and may continue to have, a material adverse effect on our financial condition and results of operations.
- We have experienced recent volatility in the market price and trading volume of our common stock and may continue to do so in the future.
- Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders’ best interests.
- Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders’ ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees.

Risks Related to Our Business

Declines in oil, natural gas, and NGL prices will adversely affect our business, financial condition or results of operations, and our ability to meet our capital expenditure obligations or targets and financial commitments.

The price we receive for our oil, natural gas, and natural gas liquids ("NGLs") heavily influences our revenue, profitability, cash flows, liquidity, access to capital, present value and quality of our reserves, and the nature and scale of our operations. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. In recent years, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 65% of our estimated proved reserves as of December 31, 2022 were oil and NGLs, our financial results are more sensitive to movements in oil and NGL prices.

During times of suppressed oil prices, we have historically experienced significant decreases in crude oil revenues and recorded unproved property asset impairment charges. Any prolonged period of low market prices for oil, natural gas, and NGLs could result in future capital expenditures being reduced and will necessarily adversely affect our business, financial condition, and liquidity and our ability to meet obligations, targets, or financial commitments. During the year ended December 31, 2022, the daily NYMEX WTI oil spot price ranged from a high of $123.64 per Bbl to a low of $71.05 per Bbl, and the NYMEX HH natural gas spot price ranged from a high of $9.85 per MMBtu to a low of $3.46 per MMBtu. As of February 20, 2023, the daily NYMEX WTI oil spot price and NYMEX HH natural gas spot price was $76.34 per Bbl and $2.28 per MMBtu, respectively.

The prices we receive for our production and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- worldwide, regional, and local economic conditions impacting the global supply and demand for oil and natural gas;
- the actions from members of the Organization of Petroleum Exporting Countries and other oil producing nations;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and involving Russia and Ukraine and conditions in South America;
- the level of domestic and global oil and natural gas exploration and production;
- the level of domestic and global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters, including the physical effects of climate change;
- local, domestic, and foreign governmental regulations, including regulations addressing climate change;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- the price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption;
- variability in subsurface reservoir characteristics, particularly in areas with immature development history, even within areas in close proximity within the same basin or field;
- the availability of pipeline capacity and infrastructure; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under contracts at market-based prices. Declines in commodity prices may have the following effects on our business:

- reduction of our revenues, profit margins, operating income, and cash flows;
- reduction in the amount of crude oil, natural gas, and NGLs that we can produce economically, and reduction in our liquidity and inability to pay our liabilities as they come due;

- certain properties in our portfolio becoming economically unviable;
- delay or postponement of some of our capital projects;
- significant reductions in future capital programs, resulting in a reduced ability to develop our reserves;
- limitations on our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;
- reduction to the borrowing base under our Credit Facility or limitations in our access to sources of capital, such as equity or debt;
- declines in our stock price;
- reduction in industry demand for crude oil;
- reduction in storage availability for crude oil;
- reduction in pipeline and processing industry demand and capacity for natural gas;
- reduction in the ability of our vendors, suppliers, and customers to continue operations due to the prevailing adverse market conditions; and
- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment.

Imbalances between the supply and demand for oil and natural gas could result in transportation and storage constraints, reductions of our planned production, and related shut-in of our wells, which could adversely affect our business, financial condition, and results of operations.

Any future excess supply of oil and natural gas (such as that which resulted from the unprecedented decline in demand for oil and natural gas stemming from various governmental actions taken in 2020 to mitigate the impact of COVID-19) could impact our ability to sell our production because of transportation or storage constraints, causing us to shut-in or curtail production or flare our natural gas. Any such prolonged shut-in of our wells may result in decreased well productivity once we are able to resume operations, and any cessation of drilling and development of our acreage could result in the expiration, in whole or in part, of our leases. The occurrence of any of these risks may, in the future, adversely affect our business, financial condition, and results of operations.

Our production is not fully hedged, and we may hedge a lower percentage of our production than we have in the past. We are therefore exposed to fluctuations in the price of oil, natural gas, and NGLs and will be affected by continuing and prolonged declines in such prices.

Oil, natural gas, and NGL prices are volatile. It is common within the industry to hedge a portion of oil and natural gas production to reduce a company's exposure to adverse fluctuations in these prices. Within our company, we have stated limitations as prescribed in our reserve-based Credit Facility, as the borrower, with JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions as lenders (the "Credit Facility") as to the percentage of our production that can be hedged. The limitations range from 85% to 100% of our projected production from our proved developed properties and 65% to 85% of our projected production from our total proved properties, dependent on the duration of the hedge. The Credit Facility also contains a minimum hedging covenant; however, the Credit Facility was amended on December 21, 2021 to provide that the minimum hedging covenant will no longer apply so long as the Company maintains its leverage ratio below 1.0:1.0. Due to the Credit Facility's restrictions and/or management's decision to hedge less than 100% of our projected production, some of our future production will be sold at market prices, exposing us to fluctuations in the price of crude oil and natural gas. Currently, we have hedged approximately 2,800 Bbls per day in 2023, and our hedging for 2024 oil production is even more limited. Accordingly, our revenues and cash flows are subject to increased volatility and may be subject to significant reduction in prices, which would have a material negative impact on our results of operations. See the *Derivative Activity* section in Part I, Item I of this Annual Report on Form 10-K for a summary of our hedging activity.

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

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we have, and may in the future enter into additional, derivative arrangements for a portion of our oil, natural gas, and NGL production, including swaps, collars, and other instruments. We have not in the past designated any of our derivative instruments as hedges for accounting purposes and have recorded all derivative instruments on our balance sheet at fair value.

Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

The agreements covering our debt have restrictive covenants that could limit our ability to finance our operations, fund capital needs, respond to changing conditions, and engage in other business activities that may be in our best interests.

The agreements governing our debt, including the Credit Facility and the indenture governing our senior notes, contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including the maintenance of certain financial ratios, including a minimum current ratio and a maximum leverage ratio. In addition, our debt agreements contain covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness;
- issue preferred stock;
- sell or transfer assets;
- pay dividends on, redeem, or repurchase capital stock;
- repurchase or redeem subordinated debt;
- make certain acquisitions and investments;
- create or incur liens;
- engage in transactions with affiliates;
- enter into agreements that restrict distributions or other payments from restricted subsidiaries to us;
- consolidate, merge, or transfer all or substantially all of our assets; and
- engage in certain other business activities.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We may not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness. As of the date of this Annual Report on Form 10-K, we are in compliance with all financial and non-financial covenants.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants contained in our debt documents. In addition, our ability to comply with the financial ratios and financial condition tests under the Credit Facility may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a continued downturn in commodity prices, our business, or the economy in general, or otherwise conduct necessary corporate activities.

Borrowings under the Credit Facility are limited by our borrowing base, which is subject to periodic redetermination.

The borrowing base under the Credit Facility is redetermined at least semiannually and up to two additional times per year between scheduled determinations upon request of us or lenders holding more than 50% of the aggregate commitments. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors.

In our fall 2022 semi-annual redetermination, the borrowing base under the Credit Facility was set at $1.85 billion with an elected committed amount of $1.0 billion.

Upon a redetermination, we could be required to repay a portion of our bank debt to the extent our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder requiring us to negotiate renewals, arrange new financing, or sell significant assets, all of which could have a material adverse effect on our business and financial results.

Our development and production projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves or anticipated production volumes.

Our development and production activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production, and acquisition of oil and natural gas reserves. At this time, we intend to finance future capital expenditures primarily through cash flows provided by operating activities and borrowings under the Credit Facility. Declines in commodity prices coupled with our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional equity securities or debt securities or the strategic sale of assets. The issuance of additional debt may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures, and acquisitions. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under the Credit Facility would be reduced unless we obtain a waiver from the lenders under the Credit Facility. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of oil and natural gas we are able to produce from new and existing wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas;
- our ability to acquire, locate, and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under the Credit Facility decreases or if our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations. If additional capital is needed, we may not be able to obtain debt or equity financing on favorable terms, or at all. If cash generated by operations or cash available under the Credit Facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our undeveloped leases and a decline in our oil and natural gas reserves, and an adverse effect on our business, financial condition, and results of operations.

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

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development, and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, lease, explore, develop, or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see *Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves* below. Our cost of drilling, completing, and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors, including, but not limited to, the following, may result in substantial losses, including personal injury or loss of life, penalties, damage or destruction of property and equipment, and curtailments, delays, or cancellations of our scheduled drilling, completion, and infrastructure projects:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- unanticipated environmental liabilities;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as extreme cold temperatures, blizzards, ice storms, tornadoes, floods, and fires;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements, such as permitting delays;
- proximity to and capacity of transportation facilities;
- title issues or inaccuracies;
- safety and/or environmental events; and
- limitations in the market for oil and natural gas.

Our estimated proved reserves and our ultimate number of prospective well development locations are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves and the production possible from our oil and gas wells is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See *Estimated Proved Reserves* under Part I, Item 1 of this Annual Report on Form 10-K for information about our estimated oil and natural gas reserves and the PV-10 (a non-GAAP financial measure) as of December 31, 2022, 2021, and 2020.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production, and engineering data. The extent, quality, and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds, and given the current volatility in pricing, such assumptions are difficult to make. Although the reserves information contained herein is prepared by independent reserves engineers, estimates of oil and natural gas reserves are inherently imprecise, particularly as they relate to state-of-the-art technologies being employed, such as the combination of hydraulic fracturing and horizontal drilling.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K and cause potential impairment charges. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices, and other factors, many of which are beyond our control.

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

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2022, 2021, and 2020, we based the estimated discounted future net revenues from our proved reserves on the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months (after adjustment for location and quality differentials), without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas and hedging instruments;
- actual cost of development and production activities;
- the amount and timing of actual production;
- the amount and timing of future development costs;
- wellbore productivity realizations above or below type curve forecast models;
- the supply and demand of oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor (the factor required by the SEC) used when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we may be required to take write-downs of the carrying values of our properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics, and other factors, from time to time, we may be required to write-down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. Given the historical price volatility in the oil and natural gas markets, prices may decline or other events may arise that would require us to record further impairments of the book values associated with oil and natural gas properties. Accordingly, we may incur significant impairment charges in the future which could have a material adverse effect on our results of operations and could reduce our earnings and stockholders' equity for the periods in which such charges are taken.

Continuing or worsening inflationary pressures and associated changes in monetary policy may result in increases to the cost of our goods, services, and personnel, which in turn could cause our capital expenditures and operating costs to rise.

Inflation has been an ongoing concern in the U.S. since 2021. Ongoing inflationary pressures may result in increases to the costs of our oilfield goods, services, and personnel, which would in turn cause our capital expenditures and operating costs to rise. Sustained levels of high inflation could cause the U.S. Federal Reserve and other central banks to continue to increase interest rates, which could have the effects of raising the cost of capital and depressing economic growth, either of which, or the combination thereof, could hurt the financial and operating results of our business.

We intend to pursue the further development of our properties in the DJ Basin through horizontal drilling and completion. Horizontal development operations can be more operationally challenging and costly relative to our historic vertical drilling operations.

Horizontal drilling is generally more complex and more expensive on a per well basis than vertical drilling. As a result, there is greater risk associated with a horizontal well program. Risks associated with our horizontal drilling program include, but are not limited to, the following, any of which could materially and adversely impact the success of our horizontal drilling program and, thus, our cash flows and results of operations:

- successfully drilling and maintaining the wellbore to planned total depth;
- landing our wellbore in the desired hydrocarbon reservoir;
- effectively controlling the level of pressure flowing from particular wells;
- staying in the desired hydrocarbon reservoir while drilling horizontally through the formation;
- running our casing through the entire length of the wellbore;
- running tools and other equipment consistently through the horizontal wellbore;
- successful design and execution of the fracture stimulation process;
- preventing downhole communications with other wells, or, in the alternative, disruption from non-simultaneous operations;
- successfully cleaning out the wellbore after completion of the final fracture stimulation stage; and
- designing and maintaining efficient forms of artificial lift throughout the life of the well.

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

We may be unable to make attractive acquisitions, and any inability to do so may disrupt our business.

In the future we may make acquisitions of producing properties or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas, and NGL prices and their applicable differentials;
- operating costs;
- location inventory; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain, and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is, where is” basis. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms or for other reasons stated herein.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms, or successfully acquire identified targets. In addition, our Credit Facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions and also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

We may not realize anticipated benefits from mergers and acquisitions.

We seek to complete acquisitions in order to strengthen our position and to create the opportunity to realize certain benefits, including, among other things, potential cost savings and potential production multiples. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as being able to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations. Acquisitions could also result in difficulties in being able to hire, train, or retain qualified personnel to manage and operate such properties.

Potential difficulties in realizing the anticipated benefits of mergers and acquisitions include:

- disruptions of relationships with customers, distributors, suppliers, vendors, landlords, joint venture partners, and other business partners as a result of uncertainty associated with such transactions;
- difficulties integrating our business with the acquired businesses in a manner that permits us to achieve the full revenue and cost savings from such transactions;
- complexities associated with managing a larger and more complex business, including difficulty addressing possible inconsistencies in, standards, controls, or operational philosophies and the challenge of integrating complex systems, technology, networks, and other assets of each of the companies in a seamless manner that minimizes any adverse impact on customers, suppliers, employees, and other constituencies;
- difficulties realizing operating synergies;
- difficulties integrating personnel, vendors, and business partners;
- loss of key employees;
- potential unknown inherited liabilities and unforeseen expenses;
- performance shortfalls at the companies as a result of the diversion of management’s attention to integration efforts; and
- disruption of, or the loss of momentum in, each company’s ongoing business.

Our future success will depend, in part, on our ability to manage our expanded business by, among other things, integrating the assets, operations, or personnel of acquired businesses in an efficient and timely manner; consolidating systems and management controls; and successfully integrating relationships with customers, vendors, and business partners. Failure to successfully manage the combined company may have an adverse effect on our business, reputation, financial condition, and results of operations.

Concentration of our operations in one core area may increase our risk of production loss.

Our assets and operations are currently concentrated in one core area: the DJ Basin in Colorado. The core area currently provides 100% of our current sales volumes and development projects.

Because our operations are not as diversified geographically as some of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including: fluctuations in prices of crude oil, natural gas, and NGLs produced from wells in the area, geologic and engineering developments associated with this area, accidents or natural disasters, restrictive governmental regulations, including ozone non-attainment, climate-action, or other legislation and/or regulation within Colorado, activist anti-industry litigation, curtailment of production, interruption in the availability of gathering, processing, or transportation infrastructure and services, and any resulting delays or interruptions of production from existing or planned new wells. Similarly, the concentration of our assets within a single producing formation exposes us to risks, such as changes in field-wide rules or local regulations, which could adversely affect development activities or production relating to the formation. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the DJ Basin, we are subject to increasing competition for drilling rigs, pressure pumping fleets, oilfield equipment, services, supplies, and qualified personnel, which may lead to periodic shortages or delays. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Further, the areas in which we operate are experiencing increasing urban and suburban expansion, which impacts the number of available drilling locations, increases governmental reach such as evolving environmental legislation or regulatory initiatives, health, safety, and environmental regulation, annexation and taxation, and increases costs and expenses due to limited locations, political activism and opposition, increased litigation risk, siting issues, and other factors. As a result of this increased risk, the Company may face difficulties securing permits, executing on our production target, meeting operations benchmarks, and other general risks to the Company that are identified herein.

We do not maintain business interruption (loss of production) insurance for our oil and gas producing properties. Loss of production or limited access to reserves in our core operating area could have a significant negative impact on our cash flows and profitability.

We face increasing risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in Colorado and elsewhere.

Opposition toward oil and gas drilling and development activity has been growing globally. Companies in the oil and gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance, and business practices. Certain activists are working to, among other things, reduce access to fee, federal, and state government lands, and delay or cancel certain projects such as the development of oil or gas shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling in the U.S., even in jurisdictions that are among the most stringent in their regulation of the industry. Further efforts could result in the following:

- delay or denial of drilling permits;
- increased local government rulemaking and/or changes to current local government rules that result in increased costs and delay or prevention of oil and gas development;
- increased demands for additional best management practices (“BMPs”) beyond what is currently required in certain operating agreements or by the COGCC;
- revocation or modification of drilling permits, operating agreements, or other necessary authorizations;
- disputes focused on the validity of active leases and record title ownership to prevent development;
- disputes focused on proximity of operations to urban and suburban communities;
- restrictions on installation or operation of production, gathering, or processing facilities;
- mandatory and excessive setbacks between drilling locations and structures and building units and/or bodies of water, disproportionately impacted communities, or other protected areas;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposal of related waste materials, such as hydraulic fracturing fluids and produced water;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about us or the oil and gas industry in general;

- increased costs of operations and development;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Specifically in Colorado, anti-development activity has both increased and become more effective in recent years. In April 2019, new legislation became effective in Colorado, which substantially changed the state's regulation of oil and gas exploration and production activities. The new law changed the mission of the COGCC from "fostering" responsible and balanced development "consistent with protection" of public health and the environment to "regulating" oil and natural gas development "to protect" public health and the environment. SB 181 also instituted several state-wide regulatory changes, namely (i) changed the composition of the COGCC to remove two seats for industry experts and add experts on wildlife/environmental protection and public health, and changed the Commissioners' employment from volunteer to full-time positions, (ii) changed Colorado's statutory pooling provisions to require that an applicant own, or obtain the consent of, more than 45% of the applicable working or mineral interest, whereas previously the consent of only one mineral interest owner was required, (iii) changed state pre-emption law such to afford local governments greater control over oil and gas siting, and (iv) initiated a comprehensive rulemaking to amend COGCC's rules consistent with the agency's revised mission.

Among the most significant changes under the legislation was the aforementioned provision giving local governments greater control over facility siting and surface impacts associated with oil and gas development. Whether an applicable local government determines to implement regulatory changes is optional, but if changes are adopted, the resulting regulations may be stricter than state requirements. Further, local governments may now inspect oil and gas operations and impose fines for leaks, spills, and emissions. Regulation in the municipalities and areas where we operate could result in increased costs, delays in securing permits and other approvals related to our operations, and otherwise materially bear on our ability to operate and drill new wells in the areas where we hold oil and gas interests. At this time, it impossible to estimate the potential impact on our business of future local actions on our ability to operate and/or drill oil and gas wells in these areas.

The legislation mandated the COGCC conduct rulemaking on environmental protection, facility siting, cumulative impacts, flowlines, wells that are inactive, temporarily abandoned, or shut-in, financial assurance, wellbore integrity, and application fees. A major rulemaking addressing a wide range of topics including facility siting, cumulative impacts, development approvals, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection took effect in January 2021. The agency has issued written guidance on many of the issues addressed to provide direction on regulatory interpretation and compliance. Among other things, the amended rules adopt an increased required setback of 2,000 feet between an oil and gas location and a residential or high occupancy building unit unless one or more conditions are satisfied to allow for a lesser setback that the COGCC determines is acceptable under the rules. In addition, as part of wildlife protections, the COGCC adopted a setback of 500 feet between oil and gas locations and/or certain operations thereon and the ordinary high water mark for certain high priority aquatic habitats, though the Colorado Parks and Wildlife Division may waive this setback beyond 300 feet.

Permitting delays that result from the new COGCC rules and regulations could substantially curtail the Company's near-term pace of new oil and gas development. We have observed a decline in the pace at which permit applications are being granted, and if this trend continues, it could have a material adverse effect on our business, financial condition, production targets, and results of operations.

Additionally, the new legislation requires the state's AQCC to undertake rulemaking efforts to minimize methane emissions and emissions of other hydrocarbons, volatile organic compounds, and nitrogen oxides associated with oil and gas facilities. The AQCC has more recently adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, the development of pre-production air monitoring plans at certain oil and gas facilities, enclosed combustion device testing, a company-wide methane intensity reduction requirement, and additional measures for reducing and eliminating emissions from pneumatic devices. The legislation also granted the AQCC regulatory authority over a broad range of oil and gas facilities during pre-production activities, drilling, and completion.

Rules adopted by the COGCC and AQCC pursuant to the new legislation may significantly increase the Company's operating costs and have a material adverse effect on our business, financial condition, and results of operations.

In addition, there have been several citizen/activist lawsuits filed against industry and state and local regulators associated with air quality, siting, environmental justice, and climate change. Such anti-development efforts are likely to continue in the future, which could result in dramatically reducing the area of future oil and gas development in Colorado or outright banning oil and gas development in Colorado. These efforts could have a material adverse effect on our business, financial condition, and results of operations.

SB 181's requirement that we own or control more than 45% of the working or mineral interest in order to statutorily pool our applicable interest may make it much more difficult for us to develop such interests, which could have a material adverse effect on our business, financial condition, and results of operations.

In some cases, we do not own more than 45% working interest or mineral interest in a prospective area of development, which is now required to statutorily pool our applicable working or mineral interests. In such cases, unless we can obtain the consent of more than 45% of all applicable working or mineral interest owners (who can be located through reasonable diligence) to pursue statutory pooling, or achieve a voluntary pooling agreement with 100% of the applicable interest owners, we may be prohibited from developing the resources in that area or having them be developed by other operators.

The COVID-19 pandemic has had, and may continue to have, a material adverse effect on our financial condition and results of operations.

We face risks related to public health crises, including the COVID-19 pandemic. The effects of the COVID-19 pandemic, including travel bans, prohibitions on group events and gatherings, shutdowns of certain businesses, curfews, shelter-in-place orders, and recommendations to practice social distancing in addition to other actions taken by both businesses and governments, resulted in a significant and swift reduction in international and U.S. economic activity. The collapse in the demand for oil caused by this unprecedented global health and economic crisis contributed to the significant decrease in crude oil prices in 2020 and had and could in the future continue to have a material adverse impact on our financial condition and results of operations.

Since the beginning of 2021, the distribution of COVID-19 vaccines progressed and many government-imposed restrictions were relaxed or rescinded. However, we continue to monitor the effects of the pandemic on our operations. As a result of the ongoing COVID-19 pandemic, our operations, and those of our operating partners, have and may continue to experience delays or disruptions and temporary suspensions of operations. In addition, our results of operations and financial condition have been and may continue to be adversely affected by the ongoing COVID-19 pandemic.

The extent to which our operating and financial results are affected by COVID-19 will depend on various factors and consequences beyond our control, such as the emergence of more contagious and harmful variants of the COVID-19 virus, the duration and scope of the pandemic, additional actions by businesses and governments in response to the pandemic, and the speed and effectiveness of responses to combat the virus. COVID-19, and the volatile regional and global economic conditions stemming from the pandemic, could also aggravate the other risk factors that we identify herein. While the effects of the COVID-19 pandemic have lessened recently in the U.S., we cannot predict the duration or future effects of the pandemic, or more contagious and harmful variants of the COVID-19 virus, and such effects may materially adversely affect our results of operations and financial condition in a manner that is not currently known to us or that we do not currently consider to present significant risks to our operations.

Terrorist attacks and armed conflict could have a material adverse effect on our business, financial condition, or results of operations.

Terrorist attacks and armed conflict may significantly affect the energy industry, including our operations and those of our current and potential customers, as well as general economic conditions, consumer confidence and spending, and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the U.S. Our insurance may not protect against such occurrences. Furthermore, commodity markets are currently also subject to heightened levels of uncertainty related to the Russian military invasion of Ukraine, which has given rise to regional instability and resulted in heightened economic sanctions by the U.S. and the international community that, in turn, could increase uncertainty with respect to global financial markets and production output from the Organization of Petroleum Exporting Countries and other oil producing nations. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations.

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

We do not operate all of the properties in which we have an interest. We own significant non-operated working interests which are not currently within our operated development plan. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures, timing, or future development of underlying properties, and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator's breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the timing and amount of capital expenditures, the available expertise and financial resources, the inclusion of other participants, and the use of technology. Our lack of control over non-operated properties also makes it more difficult for us to forecast capital expenditures, revenues, production, liability, and other related matters.

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

Approximately 17% of our total proved reserves were classified as proved undeveloped as of December 31, 2022. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate or that may be available to us. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. Our ability to drill and develop these locations is subject to a number of uncertainties, including uncertainty in the level of reserves; the availability of capital to us and other participants; seasonal conditions; regulatory approvals; activist intervention; oil, natural gas, and NGL prices; availability of permits; costs; and well performance. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking, and we may therefore be required to downgrade to probable or possible categories any proved undeveloped reserves that are not developed within this five-year time frame. These limitations may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

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

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10-K. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional evaluation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. Prior to drilling, the use of 2-D and 3-D seismic technologies, various other technologies, and the study of producing fields in the same area will still not enable us to know conclusively 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. In addition, the use of 2-D and 3-D seismic data and other technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures which may result in a reduction in our returns or increase our losses. 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. If we drill any dry holes in our current and future drilling locations, our profitability and the value of our properties will likely be reduced. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations, or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing, and operating any well is often uncertain, and new wells may not be productive.

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

The terms of our oil and gas leases often stipulate that the lease will terminate if not held by production, rentals, or otherwise some form of an extension payment to extend the term of the lease. As of December 31, 2022, approximately 36,100 net acres of our properties were not held by production. For these properties, if production in paying quantities is not established on units containing leases during the next year, then approximately 17,600 net acres will expire in 2023, approximately 4,900 net acres will expire in 2024, and approximately 13,600 net acres will expire in 2025 and thereafter. While some expiring leases may contain predetermined extension payments, other expiring leases will require us to negotiate new leases at the time of lease expiration. Further, existing leases which are currently held by production may unexpectedly encounter operational, political, regulatory, or litigation challenges which could result in their termination. It is possible that market conditions at the time of negotiation could require us to agree to new leases on less favorable terms to us than the terms of the expired leases or cause us to lose the leases entirely. If our leases expire, we will lose our right to develop the related properties.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which could adversely affect our business, financial condition, and results of operations.

In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our current proved reserves will decline as reserves are produced and, therefore, our level of production and cash flows will be affected adversely unless we conduct successful exploration and development activities or acquire properties containing proved reserves. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding, acquiring, and/or developing additional reserves. However, we cannot assure you that our future acquisition, development, and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks, including those related to our hydraulic fracturing operations.

Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including, but not limited to, the possibility of:

- environmental hazards, such as spills, uncontrollable flows of oil, natural gas, brine, well fluids, natural gas, hazardous air pollutants, or other pollution into the environment, including soil, surface water, groundwater, and shoreline contamination;
- unpermitted releases of natural gas and hazardous air pollutants or other substances into the atmosphere at our oil and gas facilities;
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in natural gas and oil we produce;
- abnormally pressured formations resulting in well blowouts, fires, or explosions;
- mechanical difficulties, such as stuck down-hole tools or casing collapse;
- cratering (catastrophic failure);
- downhole communication leading to migration of contaminants;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources, and equipment;
- pollution and other environmental and natural resource damages;

- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

The presence of H_2S, a toxic, flammable, and colorless gas, is a common risk in the oil and gas industry and may be present in small amounts for brief periods from time to time at our well and facility locations. In addition, our operations in Colorado are susceptible to damage from natural disasters, such as flooding, wildfires, tornadoes, and other natural phenomena and weather conditions, including extreme temperatures, which involve increased risks of personal injury, property damage, and marketing interruptions. The occurrence of one of these operating hazards may result in injury, loss of life, suspension of operations, environmental damage and remediation liability, and/or governmental investigations and penalties. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration and development, or could result in a loss of our properties.

As is customary in the oil and gas industry, we maintain insurance against some, but not all, of these potential risks and losses. Although we believe the coverage and amounts of insurance that we carry are consistent with industry practice, we do not have insurance protection against all risks that we face, because we choose not to insure certain risks, insurance is not available at a level that balances the costs of insurance and our desired rates of return, or actual losses exceed coverage limits. Insurance costs will likely continue to increase, which could result in our determination to decrease coverage and retain more risk to mitigate those cost increases. In addition, pollution and environmental risks generally are not fully insurable. If we incur substantial liability, and the damages are not covered by insurance or are in excess of policy limits, then our business, results of operations, and financial condition may be materially adversely affected.

Because hydraulic fracturing activities are integral to our operations, they are covered by our insurance against claims made for bodily injury, property damage, and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if the operator is unaware of the pollution event and unable to report the "occurrence" to the insurance company within the required time frame. We also do not have coverage for gradual, long-term pollution events, including climate change.

Under certain circumstances, we have agreed to indemnify third parties against losses resulting from our operations. Pursuant to our surface leases, we typically indemnify the surface owner for clean-up and remediation of the site. As owner and operator of oil and gas wells and associated gathering systems and pipelines, we typically indemnify the drilling contractor for pollution emanating from the well, while the contractor indemnifies us against pollution emanating from its equipment.

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

We are subject to stringent and complex federal, state, and local laws and regulations governing public health and occupational safety, the discharge of materials into the environment, noise emittance, light emittance, and the general protection of the environment and wildlife. These laws and regulations may impose numerous requirements on our operations, including the obligation to obtain a permit before conducting drilling or underground injection activities; restrictions on the types, quantities, and concentration of materials that may be released into the environment; limitations or prohibitions of drilling or completion activities; the application of specific health and safety criteria to protect the public or workers; and the responsibility for cleaning up pollution resulting from operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our operations; delays in granting permits; or even the cancellation of leases and/or permits.

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

Evolving legislation or regulatory initiatives, including those related to hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.

We are subject to extensive federal, state, and local laws and regulations, including those concerning public and occupational health and safety and environmental protection. Governmental authorities frequently review, revise, and supplement these requirements, and both oil and gas development generally, and hydraulic fracturing specifically, are receiving increasing legislative and regulatory attention. For example, the COGCC has revised its regulations on a range of topics including facility siting, development approvals, cumulative impacts, asset transfers, pollution standards, hearings and variances, groundwater monitoring, underground injection control and enhanced recovery wells, venting and flaring restrictions, spill reporting, cleanup responsibility, and wildlife protection. Additionally, financial assurance rulemaking was completed by the COGCC in early 2022, which will impact fees required for surety bonding and includes comprehensive language that addressed the transfer of wells and plugging and abandonment obligations. Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. Hydraulic fracturing involves the injection of water, proppant, and chemicals under pressure into rock formations to stimulate hydrocarbon production.

In some instances, certain state and local governments are adopting new requirements on hydraulic fracturing and other oil and gas operations. Some counties in Colorado, for instance, have amended their land use regulations to impose new siting and other requirements on oil and gas development, while other local governments have entered memoranda of agreement with oil and gas producers to accomplish the same or similar objectives. Under current Colorado law, local governments can regulate both facility siting and the surface impacts associated with oil and gas development, and local government regulations may be more protective or stricter than State requirements. In addition, voters in Colorado have proposed or advanced ballot initiatives restricting or banning oil and gas development in Colorado. Because our operations and reserves are solely located in Colorado, the risks we face with respect to such ballot initiatives are greater than other companies with more geographically diverse operations.

The adoption of future federal, state, or local laws or implementing regulations imposing new environmental, operational, and/or financial assurance obligations on, or otherwise limiting, our operations could make it more difficult, more expensive, and/or impossible to complete oil and natural gas wells, increase our costs of compliance operations, delay or prevent the development of certain resources (including especially shale formations that are not commercial without the use of hydraulic fracturing), or alter the demand for and consumption of our products. We cannot assure that any such outcome would not be material, and any such outcome could have a material adverse impact on our cash flows and results of operations.

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

There is a broad consensus of scientific opinion that human-caused (anthropogenic) emissions of GHGs are linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and the demand for and consumption of our products (due to potential changes in both costs and weather patterns).

The EPA also adopted regulations requiring the reporting of GHG emissions from specific categories of higher GHG emitting sources in the U.S., including certain oil and natural gas production facilities, which include certain of our operations. Information in such reporting may form the basis for further GHG regulation. Further, the EPA has continued with its comprehensive strategy for further reducing methane emissions from oil and gas operations, with a final rule being issued in June 2016 as part of the Subpart OOOOa NSPS. Further, on November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule would establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. On November 15, 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters". The EPA is expected to issue a final rule by August 2023. The EPA's GHG rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

In the meantime, many states already have taken such measures, which have included renewable energy standards, development of GHG emission inventories or cap and trade programs, and the adoption of ambitious climate action targets in Colorado under HB 19-1261.

Additionally, the SEC issued a proposed rule in March 2022 that would mandate extensive disclosure of climate-related data, risks, and opportunities, including financial impacts, physical and transition risks, related governance and strategy, and GHG emissions, for certain public companies. We cannot predict the costs of implementation or any potential adverse impacts resulting from the rulemaking. To the extent this rulemaking is finalized as proposed, we could incur increased costs relating to the assessment and disclosure of climate-related risks. We may also face increased litigation risks related to disclosures made pursuant to the rule if finalized as proposed. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors. See "Item 1. *Business—Climate Change*" for a further discussion of the laws and regulations related to GHGs and of climate change. The adoption of legislation or regulatory programs to reduce emissions of GHGs (including carbon pricing schemes), or the adoption and implementation of regulations that require reporting of GHG emissions or other climate-related information, could adversely affect our business and our industry, including by requiring us to incur increased operating costs, such as costs to purchase and operate emissions and vapor control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements as well as by restricting our ability to execute on our business strategy, reducing our access to financial markets, or creating greater potential for governmental investigations or litigation. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition, and results of operations. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for the oil and natural gas we produce.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere and climate change may produce significant physical effects on weather conditions, such as increased frequency and severity of droughts, storms, floods, and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves, which may not be fully insured. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods, increases in our costs of operation, or reductions in the efficiency of our operations, increases in market prices of or limited access to raw materials such as energy and water, impacts on our personnel, supply chain, or distribution chain, as well as potentially increased costs for insurance coverages in the aftermath of such effects. Any of these effects could have an adverse effect on the Company's assets and operations. Our ability to mitigate the adverse physical impacts of climate change depends in part upon our disaster preparedness and response and business continuity planning. Further, energy needs could increase or decrease as a result of extreme weather conditions depending on the duration and magnitude of any such climate changes. Increased energy use due to weather changes may require us to invest in additional equipment to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues. The effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Transition risks related to climate change, including negative shift in investor sentiment with respect to the oil and gas industry, could have material and adverse effects on us.

Increasing attention from governmental and regulatory bodies, investors, consumers, industry, and other stakeholders on combatting climate change, together with changes in consumer and industrial/commercial behavior, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary climate-related disclosures, preferences and attitudes with respect to the generation and consumption of energy, the use of hydrocarbons, and the use of products manufactured with, or powered by, hydrocarbons, may result in the enactment of climate change-related regulations, policies, and initiatives (at the government, regulator, corporate, and/or investor community levels), including alternative energy requirements, new fuel consumption standards, energy conservation and emissions reductions, measures and responsible energy development; technological advances with respect to the generation, transmission, storage, and consumption of energy (including advances in wind, solar, and hydrogen power, as well as battery technology); increased availability of, and increased demand from consumers and industry for, energy sources other than oil and natural gas (including wind, solar, nuclear, and geothermal sources as well as electric vehicles); and development of, and increased demand from consumers and industry for, lower-emission products and services (including electric vehicles and renewable residential and commercial power supplies) as well as more efficient products and services. These developments may in the future adversely affect the demand for products manufactured with, or powered by, petroleum products, as well as the demand for, and in turn the prices of, the products that we sell, the Company’s stock price and access to capital markets, and the availability to us of necessary third-party services and facilities that we rely on, which may increase our operational costs and adversely affect our ability to successfully carry out the Company’s business strategy.

Furthermore, the oil and natural gas industry, and energy industry more broadly, is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, including technological advances in fuel economy and energy generation devices or other technological advances that could reduce demand for oil and natural gas, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement new technologies at substantial costs. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition, or results of operations could be materially and adversely affected.

Certain segments of the investor community have developed negative sentiment towards investing in our industry, and such negative sentiment and related reputational risks may also adversely affect our ability to successfully carry out our business strategy by adversely affecting our access to capital. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments, and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain investment banks and asset managers based both domestically and internationally have announced that they are adopting climate change guidelines for their banking and investing activities. Institutional lenders who provide financing to energy companies such as ours have also become more attentive to sustainable lending practices, and some may elect not to provide traditional energy producers or companies that support such producers with funding. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding or higher cost of capital for potential development projects as well as the restriction, delay, or cancellation of infrastructure projects and energy production activities, ultimately impacting our future financial results.

Additionally, negative public perception regarding us and/or our industry may lead to increased regulatory, legislative, and judicial scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines, and enforcement interpretations. Additionally, environmental groups, landowners, local groups, and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt, or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens, and increased risk of litigation. Further, a number of cities and other local governments have sought to bring suit against the largest oil and gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or customers. Private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages, or other liabilities. While the Company's business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact the Company's operations and could have an adverse impact on the Company's financial condition.

Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business. In addition, various officials and candidates at the federal, state, and local levels have made climate-related pledges or proposed banning hydraulic fracturing altogether. More broadly, the enactment of climate change-related policies and initiatives across the market at the corporate level and/or investor community level may in the future result in increases in the Company's compliance costs and other operating costs and have other adverse effects (e.g., greater potential for governmental investigations or litigation). For further discussion regarding the transition risks posed to us by climate change-related regulations, policies, and initiatives, see the discussion above in "Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects."

Increasing scrutiny and changing stakeholder expectations in respect of ESG and sustainability practices may have an adverse effect on our business, financial condition, and results of operations and damage our reputation.

In recent years, companies across all industries are facing increasing scrutiny from a variety of stakeholders, including investor advocacy groups, proxy advisory firms, certain institutional investors, and lenders, investment funds and other influential investors and rating agencies, related to their ESG and sustainability practices. If we do not adapt to or comply with investor or other stakeholder expectations and standards on ESG matters (or meet sustainability goals and targets that we have set), as they continue to evolve, or if we are perceived to have not responded appropriately or quickly enough to growing concern for ESG and sustainability issues, regardless of whether there is a regulatory or legal requirement to do so, we may suffer from reputational damage and our business, financial condition, and/or stock price could be materially and adversely affected.

In addition, the Company's continuing efforts to research, establish, accomplish, and accurately report on the implementation of our ESG strategy, including any specific ESG objectives, may also create additional operational risks and expenses and expose us to reputational, legal, and other risks. While we create and publish voluntary disclosures regarding ESG matters from time to time, some of the statements in those voluntary disclosures may be based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring, and reporting on many ESG matters. In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital.

Further, our operations and projects require us to have strong relationships with various key stakeholders, including our shareholders, employees, suppliers, customers, local communities, and others. We may face pressure from stakeholders, many of whom are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint, and promote sustainability while at the same time remaining a successfully operating public company. If we do not successfully manage expectations across these varied stakeholder interests, it could erode stakeholder trust and thereby affect our brand and reputation. Such erosion of confidence could negatively impact our business through decreased demand, delays in projects, increased legal action and regulatory oversight, adverse press coverage and other adverse public statements, difficulty hiring and retaining top talent, difficulty obtaining necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms, and difficulty securing investors and access to capital.

We are exposed to credit risks of our hedging counterparties, third parties participating in our wells, and our customers.

Our principal exposures to credit risk are through receivables resulting from commodity price derivatives instruments, joint interest billings, and other components of $135.8 million at December 31, 2022, and the sale of our oil, natural gas, and NGLs production of $343.5 million in receivables at December 31, 2022, which we market to energy marketing companies, refineries, and affiliates.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells.

We are also subject to credit risk due to concentration of our oil, natural gas, and NGLs receivables with significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic, political, and other conditions.

We are exposed to credit risk in the event of default of our counterparty, principally with respect to hedging agreements, but also with respect to insurance contracts and bank lending commitments. We do not require most of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with our business.

The Dodd-Frank Act establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act also establishes margin requirements and certain transaction clearing and trade execution requirements. The Dodd-Frank Act may require us to comply with margin requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may be more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

We may be involved in legal cases that may result in substantial liabilities.

Like many oil and gas companies, we are involved in various legal and other cases, such as title, royalty, or contractual disputes, regulatory compliance matters, and personal injury or property damage matters, in the ordinary course of our business. Such legal cases are inherently uncertain, and their results cannot be predicted. Regardless of the outcome, such cases could have an adverse impact on us because of legal costs, diversion of management and other personnel, and other factors. In addition, it is possible that a resolution of one or more such cases could result in liability, penalties, or sanctions, as well as judgments, consent decrees, or orders requiring a change in our business practices, which could materially and adversely affect our business, operating results, and financial condition. Accruals for such liability, penalties, or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other cases could change from one period to the next, and such changes could be material.

We are subject to federal, state, and local taxes and may become subject to new taxes, and certain federal income tax deductions and state income tax deductions and exemptions currently available with respect to oil and gas exploration and development may be eliminated or reduced as a result of future legislation.

The federal, state, and local governments in the areas in which we operate (i) impose taxes on the oil and natural gas products we sell, and (ii) for many of our wells, impose sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases, unexpectedly may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals.

There have been proposals for legislative changes that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. Any such changes in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations, and cash flow.

In Colorado, there may be proposals for legislative changes that, if enacted into law, could substantially increase our severance tax and ad valorem tax effective rates. Such changes may include, but are not limited to, (i) the reduction or elimination of the credit against severance tax based on the property tax we pay; (ii) the reduction or elimination of certain exemptions impacting severance tax liability; and (iii) increased severance tax rates. Any such changes to Colorado's ad valorem and severance tax laws could negatively affect our financial condition, results of operations, and cash flow.

On August 16, 2022, legislation commonly known as the Inflation Reduction Act was signed into law. Among other things, the Inflation Reduction Act includes a 1% excise tax on corporate stock repurchases, applicable to repurchases after December 31, 2022, and also a new minimum tax based on book income. We are in the process of evaluating the potential impacts of the Inflation Reduction Act to us. While we do not currently expect the Inflation Reduction Act to have a material impact on our effective tax rate, our analysis of the effect of the Inflation Reduction Act on us is ongoing and incomplete, and it is possible that the Inflation Reduction Act (or implementing regulations and other guidance, which have not yet been issued) could adversely impact our current and deferred federal tax liability.

Changes to federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including production, severance, or similar taxes) could negatively affect our financial condition, results of operations, and cash flow.

Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.

We are subject to taxes by U.S. federal, state, and local tax authorities. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including changes in the valuation of our deferred tax assets and liabilities, expected timing and amount of the release of any tax valuation allowances, or changes in tax laws, regulations, or interpretations thereof. In addition, we may be subject to audits of our income, sales, and other transaction taxes by U.S. federal, state, and local taxing authorities. Outcomes from these audits could have an adverse effect on our financial condition, and results of operations.

The HighPoint, Extraction, and Crestone Peak Mergers triggered a limitation on the utilization of our historic U.S. NOLs, HighPoint's NOLs, Extraction's NOLs, and Crestone Peak's NOLs.

Our ability to utilize NOLs (including NOLs of HighPoint, Extraction, and Crestone Peak) to reduce future taxable income following the HighPoint, Extraction, and Crestone Peak Mergers depends on many factors, including our future income, which cannot be assured. Section 382 of the Code generally imposes an annual limitation upon the occurrence of an "ownership change" resulting from issuances of a company's stock or the sale or exchange of such company's stock by certain stockholders if, as a result, there is an aggregate change of more than 50% in the beneficial ownership of such company's stock by such stockholders within a rolling three-year period. The limitation with respect to such loss carryforwards generally would be equal to (i) the fair market value of the company's equity immediately prior to the ownership change multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax-exempt bonds during the month in which the ownership change occurs. Based on the information currently available, we believe that the transactions in connection with the HighPoint, Extraction, and Crestone Peak Mergers, will result in an ownership change with respect to us, HighPoint, Extraction, and Crestone Peak, which would trigger a limitation (calculated as described above) on our ability to utilize any historic NOLs following the HighPoint, Extraction, and Crestone Peak Mergers. Extraction's NOLs are already limited under Section 382 of the Code as a result of an ownership change that occurred in connection with Extraction's Chapter 11 cases.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption, or financial loss.

The oil and gas industry is highly dependent on digital technologies to conduct certain exploration, development, production, processing, and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment, and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. Pipelines, refineries, power stations, and distribution points for both fuels and electricity are increasingly more interconnected by computer systems. We also depend on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to process and record financial and operating data, communicate with our employees and business parties, analyze seismic and drilling information, estimate quantities of oil and gas reserves, as well as other activities related to our business. We also collect and store sensitive data in the ordinary course of our business, including personally identifiable information of our employees as well as our proprietary business information and that of our customers, suppliers, investors, and other stakeholders. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. The secure processing, maintenance, and transmission of information is critical to our operations, and we monitor our key information technology systems in an effort to detect and prevent cyber-attacks, security breaches, or unauthorized access. At the same time, cyber incidents, including deliberate attacks or unintentional events, have continued to increase in frequency and are becoming increasingly sophisticated. Despite our security measures, our technologies, systems, networks, and those of our vendors, suppliers, and other business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, weaknesses in the cyber security of our vendors, suppliers, and other business partners could facilitate an attack on our technologies, systems, and networks. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Given the politically sensitive nature of hydraulic fracturing and the controversy generated by its opponents, our technologies, systems, and networks may be of particular interest to certain ideological groups, which may seek to launch cyber-attacks as a method of advancing their agenda. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient.

As cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our personnel, information, facilities, and infrastructure may result in increased capital and operating costs. A cyber-attack or security breach could result in liability under data privacy laws, regulatory penalties, damage to our reputation, or loss of confidence in us, or additional costs for remediation and modification or enhancement of our information systems to prevent future occurrences, all of which could have a material and adverse effect on our business, financial condition, or results of operations. To date we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer such losses in the future. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations.

Risks Related to our Common Stock

We have experienced recent volatility in the market price and trading volume of our common stock and may continue to do so in the future.

The trading price of shares of our common stock has fluctuated widely and in the future may be subject to similar fluctuations. As an example, during the 2022 calendar year, the sales price of our common stock ranged from a low of $44.17 per share to a high of $84.76 per share. The trading price of our common stock may be affected by a number of factors, including the volatility of oil, natural gas, and NGL prices, our operating results, changes in our earnings estimates, additions or departures of key personnel, our financial condition and liquidity, drilling activities, legislative and regulatory changes, general conditions in the oil and natural gas exploration and development industry, general economic conditions, and general conditions in the securities markets. In particular, a significant or extended decline in oil, natural gas, and NGL prices could have a material adverse effect our sales price of our common stock. Other risks described in this annual report could also materially and adversely affect our share price.

Although our common stock is listed on the New York Stock Exchange, we cannot assure you that an active public market will continue for our common stock or that we will be able to continue to meet the listing requirements of the NYSE. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us.

Our ability to pay dividends to our stockholders is restricted by applicable laws and regulations and requirements under certain of our debt agreements, including the Credit Facility and the indenture governing our senior notes.

Holders of our common stock are only entitled to receive such cash dividends as our Board, in its sole discretion, may declare out of funds legally available for such payments. In May 2021, we announced the initiation of a quarterly base cash dividend and, in March 2022, the Board approved the initiation of a quarterly variable cash dividend, assuming pro forma compliance with certain leverage targets. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board. Our Board's determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon, among other things, our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law, and other factors that our Board deems relevant at the time of such determination. We cannot assure you, however, that we will pay dividends in the future in the current amounts or at all. Our Board may change the timing and amount of any future dividend payments or eliminate the payment of future dividends to our common stockholders at its discretion, without notice to our stockholders. Our ability to declare and pay dividends to our stockholders is subject to certain laws, regulations, and policies, including minimum capital requirements and, as a Delaware corporation, we are subject to certain restrictions on dividends under the Delaware General Corporation Law (the "DGCL"). Under the DGCL, our Board may not authorize payment of a dividend unless it is either paid out of our surplus, as calculated in accordance with the DGCL, or if we do not have a surplus, it is paid out of our net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, our ability to pay cash dividends to our stockholders may be limited by covenants in any debt agreements that we are currently a party to, including the Credit Facility and the indenture governing our senior notes, or may enter into in the future. As a consequence of these various limitations and restrictions, we may not be able to make, or may have to reduce or eliminate at any time, the payment of dividends on our common stock. If as a result, we are unable to pay dividends, investors may be forced to rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Any change in the level of our dividends or the suspension of the payment thereof could have a material adverse effect on the market price of our common stock.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders' best interests.

Our certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- advance notice provisions for stockholder proposals and nominations for elections to the Board to be acted upon at meetings of stockholders; and
- limitations on the ability of our stockholders to call special meetings or act by written consent.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board.

The Kimmeridge Fund and CPPIB Crestone Peak Resources Canada Inc., a Canadian corporation (the "Crestone Peak Stockholder") became significant holders of our Common Stock following completion of the Extraction Merger and the Crestone Peak Merger.

Upon completion of the Extraction Merger and the Crestone Peak Merger, a private investment fund managed by Kimmeridge Energy Management Company, LLC, which owns shares through a subsidiary, Kimmeridge Chelsea, LLC, (the "Kimmeridge Fund") owns approximately 14% of our Common Stock, representing approximately 14% of our combined voting power, and the Crestone Peak Stockholder owns approximately 25% of our Common Stock, representing approximately 25% of our combined voting power. Subsequent to year-end, the Company entered into a privately-negotiated share purchase agreement with the Crestone Peak Stockholder for the purchase of approximately 4.9 million shares of the Company's common stock. Following the share purchase, the Crestone Peak Stockholder remained the Company's largest shareholder. In addition, upon completion of the Extraction Merger, Mr. Benjamin Dell, independent chairman of the Extraction board and a Manager of the Kimmeridge Fund, became chairman of the Board of Directors of the Company; and he served as the Interim Chief Executive Officer from January 31, 2022 until May 2, 2022. As a result, we believe that the Kimmeridge Fund and the Crestone Peak Stockholder may or will have some ability to influence our management and affairs. Further, the existence of a new significant stockholder may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may view as being in their best interests or in our best interests.

In the event that the Kimmeridge Fund or the Crestone Peak Stockholder continue to be the owner of a significant amount of our Common Stock, the prospect that they may be able to influence matters requiring stockholder approval may continue. In any of these matters, the interests of the Kimmeridge Fund or the Crestone Peak Stockholder and of our other stockholders may differ or conflict. Moreover, in the event that the Kimmeridge Fund or the Crestone Peak Stockholder continue to be the owner of a significant concentration of our Common Stock, such an ownership stake may also adversely affect the trading price of our Common Stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

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

Our certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum shall be the Court of Chancery of the State of Delaware for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer, employee, or agent of ours to us or to our stockholders, (iii) any action asserting a claim against us arising pursuant to any provision of the DGCL, our certificate of incorporation or our bylaws (or any action to interpret, apply, or enforce any provision thereof), or (iv) any action asserting a claim against us governed by the internal affairs doctrine, in each such case subject to said court of chancery having personal jurisdiction over the indispensable parties named as defendants therein.

Our exclusive forum provision is not intended to apply to claims arising under the Securities Act or the Exchange Act. To the extent the provision could be construed to apply to such claims, there is uncertainty as to whether a court would enforce the forum selection provision with respect to such claims, and in any event, our stockholders would not be deemed to have waived our compliance with federal securities laws and the rules and regulations thereunder. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock is deemed to have received notice of and consented to the foregoing forum selection provision. This provision may limit our stockholders' ability to bring a claim in a judicial forum that they find favorable for disputes with us or our directors, officers, or other employees, which may discourage such lawsuits. Alternatively, if a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition, prospects, or results of operations.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

The information required by Item 2. is contained in Item 1. *Business* and is incorporated herein by reference.

Item 3. *Legal Proceedings.*

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health, and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities.

Boulder County. In prior periods, there was ongoing litigation between Boulder County and Extraction which has been previously disclosed as having the potential to prevent oil and gas operations for the development of minerals contained within Boulder County, Colorado. Boulder County had initiated suit in District Court for Boulder County that was primarily a contract case, where the relevant contracts were the conservation easement over the Blue Paintbrush location, Extraction's Surface Use Agreement for the Blue Paintbrush location, and the leases that Boulder owns within the Blue Paintbrush drilling and spacing unit. Boulder sought invalidation of these leases in the litigation. This litigation has been resolved as to all substantive issues, and the Company is awaiting final dismissal of the matter by the trial court.

In May 2022, the Company became aware that Boulder County is alleging new legal theories and requesting termination of the leases previously at issue in the Blue Paintbrush litigation. No formal action has been initiated, but the Company intends to vigorously defend against all claims alleged by Boulder County. If an action is brought by Boulder County, an adverse outcome in any such litigation could result in the Company failing to meet its development objectives in Blue Paintbrush.

Item 4. *Mine Safety Disclosures.*

Not applicable.

PART II

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

Market for Registrant's Common Equity. Our common stock is listed on the NYSE under the symbol "CIVI".

Holders. As of February 20, 2023, there were approximately 110 registered holders of our common stock.

Dividend Policy. In May 2021, we announced the initiation of a quarterly base cash dividend on our common stock. In March 2022, the Board approved the initiation of a quarterly variable cash dividend in addition to the aforementioned base dividend, equal to 50% of free cash flow after the base cash dividend for the preceding twelve-month period and pro forma for all acquisition and divestiture activity, assuming pro forma compliance with certain leverage targets. During the nine months ended September 30, 2022, the quarterly base dividend was $0.46 per share of common stock ($1.85 annually) and was increased to $0.50 per share of common stock ($2.00 annually) beginning in the fourth quarter of 2022.

The decision to pay any future dividends is solely within the discretion of, and subject to approval by, the Board. The Board's determination with respect to any such dividends, including the record date, the payment date, and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law, and other factors that the Board deems relevant at the time of such determination. Additionally, covenants contained in our Credit Facility and the indentures governing our senior notes restrict the payment of cash dividends on our common stock, as discussed further in *Item 8, Note 5 - Long-Term Debt* of this report.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2022.

	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Be Purchased Under Plans or Programs
October 1, 2022 - October 31, 2022	1,504	$ 67.52	—	—
November 1, 2022 - November 30, 2022	1,109	$ 71.26	—	—
December 1, 2022 - December 31, 2022	4,844	$ 67.93	—	—
Total	7,457	$ 68.62	—	—

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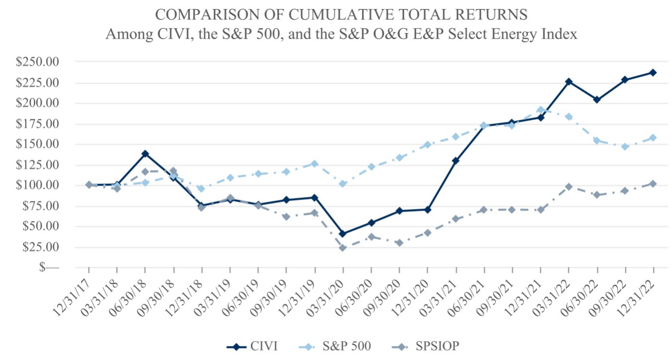
(1) Represent shares that employees surrendered back to us that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced plan or program to repurchase shares of our common stock, nor do we have a publicly announced plan or program to repurchase shares of our common stock.

Sale of Unregistered Securities. We had no sales of unregistered securities during the year ended December 31, 2022.

Stock Performance Graph. The following performance graph shall not be deemed "filed" for purposes of Section 18 of the Exchange Act, or otherwise subject to liabilities under that section and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

The following graph compares the cumulative total stockholder return for the Company's common stock, the Standard and Poor's 500 Stock Index (the "S&P 500 Index") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P Index") over the five year period from December 31, 2017 through December 31, 2022. The graph assumes that $100 was invested on December 31, 2017 in each of the common stock of the Company, the S&P 500 Index, and the S&P O&G E&P Index and assumes reinvestment of any dividends. The stock price performance on the following graph is not necessarily indicative of future stock price performance.



Item 6. *[Reserved].*

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

The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. Such forward-looking statements should be read in conjunction with our disclosures under *Part I, Item 1A, Risk Factors* of this Form 10-K.

This section of this Form 10-K generally discusses 2022 and 2021 results and year-to-year comparisons between 2022 and 2021. Discussions of 2020 items and year-to-year comparisons between 2021 and 2020 that are not included in this Form 10-K can be found in *Management's Discussion and Analysis of Financial Condition and Results of Operations* in *Part II, Item 7* of our Annual Report on Form 10-K for the fiscal year ended December 31, 2021.

Executive Summary

We are an independent exploration and production company focused on the acquisition, development, and production of oil and associated liquids-rich natural gas in the Rocky Mountain region, primarily in the DJ Basin of Colorado. We believe our acreage in the DJ Basin has been significantly delineated by our own drilling success and by the success of offset operators, providing confidence that our results are repeatable and will continue to generate economic returns. The majority of our revenues are generated through the sale of oil, natural gas, and natural gas liquids production.

The Company's primary objective is to maximize shareholder returns by responsibly developing our oil and natural gas resources. To achieve this, Civitas is guided by four foundational pillars that we believe add long-term, sustainable value. These pillars are: generate free cash flow, maintain a premier balance sheet, return free cash flow to shareholders, and demonstrate ESG leadership.

Financial and Operating Results

Our financial and operational results include:

- Crude oil equivalent sales volumes increased 204% for the year ended December 31, 2022 when compared to the same period during 2021 primarily due to the HighPoint, Extraction, and Crestone Peak mergers, as well as the Bison Acquisition;
- General and administrative expense per Boe decreased by 28% for the year ended December 31, 2022 when compared to the same period during 2021 due to the synergies achieved through the HighPoint, Extraction, and Crestone Peak mergers as well as the Bison Acquisition;
- Lease operating expense per Boe increased by 7% per Boe for the year ended December 31, 2022 when compared to the same period during 2021;
- Total liquidity was $1.8 billion at December 31, 2022, consisting of cash on hand plus unused borrowing capacity from our Credit Facility. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Cash dividends of $536.9 million, or $6.29 per share, declared and paid during the year ended December 31, 2022;
- Cash flows provided by operating activities for the year ended December 31, 2022 were $2.5 billion, as compared to $274.6 million during the year ended December 31, 2021. Please refer to *Liquidity and Capital Resources* below for additional discussion;
- Capital expenditures, inclusive of accruals, were $988.5 million during the year ended December 31, 2022, of which $74.4 million represents land and midstream capital expenditures; and
- Proved reserves of 416.0 MMBoe as of December 31, 2022 increased by 5% when compared to proved reserves as of December 31, 2021.

Midstream Assets

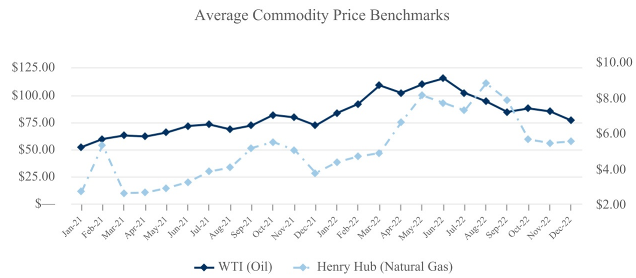
The Company's midstream assets provide reliable gathering, treating, and storage for the Company's operated production while reducing facility site footprints, leading to more cost-efficient operations and reduced emissions and surface disturbance per Boe produced. Additionally, this infrastructure helps ensure that the Company's production is not constrained by any single midstream service provider. The net book value of the Company's midstream assets was $326.8 million as of December 31, 2022.

Current Events and Outlook

Commodity prices continue to be impacted by various macro-economic factors influencing the balance of supply and demand. Commodity prices strengthened in 2021 and continued to strengthen throughout the majority of 2022, which has significantly improved our earnings and ability to generate free cash flow. The increase in commodity prices was primarily driven by increased demand resulting from the global recovery from the COVID-19 pandemic. Additionally, Russia's invasion of Ukraine and related economic sanctions imposed on Russia, as well as OPEC+ restraining production growth, further augmented supply shortages, causing oil prices to increase even more throughout most of 2022.

However, the economy is experiencing uncertainty surrounding inflation and increased interest rates, as evidenced by the decline of oil prices in the fourth quarter of 2022. Inflationary pressures could result in increases to our capital and operating expenses and could impact the cost of oilfield services, equipment, and personnel retention, among other things. Increases in interest rates as a result of inflation and a potentially recessionary economic environment in the United States could also have a negative effect on the demand for oil and natural gas. The foregoing destabilizing factors have caused dramatic fluctuations in global financial markets and uncertainty about world-wide oil and natural gas supply and demand, which in turn has increased the volatility of oil and natural gas prices.

The below graph depicts month average NYMEX WTI oil and NYMEX natural gas HH spot price over the years ended December 31, 2022 and December 31, 2021.



While WTI oil prices have strengthened, in light of uncertainty associated with oil and natural gas demand, future monetary policy relating to inflationary pressures, and governmental policies aimed at transitioning toward lower carbon energy, we cannot predict any future volatility in or levels of commodity prices or demand for oil and natural gas.

Our 2023 drilling and completion capital budget of $725 million to $825 million contemplates running an average of 2 operated rigs and 2 operated crews that will drill 100 to 110 and complete 120 to 130 gross operated wells. Additionally, we intend to invest approximately $75 million to $85 million in land, midstream, and other capital activity, inclusive of approximately $11 million towards ESG emissions reduction initiatives. Further, we have allocated $8 million in the 2023 budget toward the purchase of carbon offsets and renewable energy credits. Despite the prevalence of climate change-related regulations, policies and initiatives (across the market at the corporate level and/or investor community level), we did not incur any material increase in compliance costs related to climate change in the year ended December 31, 2022, and we do not presently anticipate the incurrence of any material increases in future periods.

Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and the notes thereto contained in *Item 8* of this Annual Report on Form 10-K. Comparative results of operations for the period indicated are discussed below.

The following table summarizes our product revenues, sales volumes, and average sales prices for the periods indicated:

	Year Ended December 31, 2022	Year Ended December 31, 2021	Change	Percent Change
Revenues (in thousands):				
Crude oil sales[1]	$ 2,535,496	$ 613,804	$ 1,921,692	313 %
Natural gas sales[2]	691,903	141,090	550,813	390 %
NGL sales	560,185	171,095	389,090	227 %
Product revenue	$ 3,787,584	$ 925,989	$ 2,861,595	309 %
Sales Volumes:				
Crude oil (MBbls)	27,650.1	9,384.6	18,265.5	195 %
Natural gas (MMcf)	112,478.3	36,763.4	75,714.9	206 %
NGL (MBbls)	15,666.4	4,933.6	10,732.8	218 %
Crude oil equivalent (MBoe)[3]	62,062.9	20,445.4	41,617.5	204 %
Average Sales Prices (before derivatives)[4]:				
Crude oil (per Bbl)	$ 91.70	$ 65.41	$ 26.29	40 %
Natural gas (per Mcf)	$ 6.15	$ 3.84	$ 2.31	60 %
NGL (per Bbl)	$ 35.76	$ 34.68	$ 1.08	3 %
Crude oil equivalent (per Boe)[3]	$ 61.03	$ 45.29	$ 15.74	35 %
Average Sales Prices (after derivatives)[4]:				
Crude oil (per Bbl)	$ 79.17	$ 42.49	$ 36.68	86 %
Natural gas (per Mcf)	$ 4.47	$ 2.43	$ 2.04	84 %
NGL (per Bbl)	$ 33.14	$ 32.84	$ 0.30	1 %
Crude oil equivalent (per Boe)[3]	$ 51.73	$ 31.80	$ 19.93	63 %

(1) Crude oil sales excludes $0.6 million and $1.0 million of oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2022 and 2021, respectively.
(2) Natural gas sales excludes $3.2 million and $3.6 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2022 and 2021, respectively.
(3) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.
(4) Derivatives economically hedge the price we receive for oil, natural gas, and NGL. For the year ended December 31, 2022, the derivative cash settlement loss for oil, natural gas, and NGLs was $346.4 million, $189.4 million, $41.0 million, respectively. For the year ended December 31, 2021, the derivative cash settlement loss for oil, natural gas, and NGLs was $215.1 million, $51.8 million, and $9.1 million, respectively. Please refer to *Item 8, Note 9 - Derivatives* for additional disclosures.

Product revenues increased by 309% to $3.8 billion for the year ended December 31, 2022 compared to $926.0 million for the year ended December 31, 2021. The increase was largely due to a 204% increase in sales volumes and a $15.74, or 35%, increase in oil equivalent pricing, excluding the impact of derivatives. The increase in sales volumes is due to the HighPoint Merger that closed on April 1, 2021, the Extraction and Crestone Peak mergers that closed on November 1, 2021, and the Bison Acquisition that closed on March 1, 2022. Additionally, we turned 146 gross wells to sales during the year ending December 31, 2022.

The following table summarizes our operating expenses for the periods indicated (in thousands, except per Boe amounts):

	Year Ended December 31, 2022	Year Ended December 31, 2021	Change	Percent Change
Operating Expenses:				
Lease operating expense	$ 169,986	$ 52,391	$ 117,595	224 %
Midstream operating expense	31,944	17,426	14,518	83 %
Gathering, transportation, and processing	287,474	64,507	222,967	346 %
Severance and ad valorem taxes	305,701	65,113	240,588	369 %
Exploration	6,981	7,937	(956)	(12)%
Depreciation, depletion, and amortization	816,446	226,931	589,515	260 %
Abandonment and impairment of unproved properties	17,975	57,260	(39,285)	(69)%
Unused commitments	3,641	7,692	(4,051)	(53)%
Bad debt expense (recovery)	(950)	607	(1,557)	(257)%
Merger transaction costs	24,683	43,555	(18,872)	(43)%
General and administrative expense	143,477	65,132	78,345	120 %
Operating expenses	$ 1,807,358	$ 608,551	$ 1,198,807	197 %
Selected Costs ($ per Boe):				
Lease operating expense	$ 2.74	$ 2.56	$ 0.18	7 %
Midstream operating expense	0.51	0.85	(0.34)	(40)%
Gathering, transportation, and processing	4.63	3.16	1.47	47 %
Severance and ad valorem taxes	4.93	3.18	1.75	55 %
Exploration	0.11	0.39	(0.28)	(72)%
Depreciation, depletion, and amortization	13.16	11.10	2.06	19 %
Abandonment and impairment of unproved properties	0.29	2.80	(2.51)	(90)%
Unused commitments	0.06	0.38	(0.32)	(84)%
Bad debt expense (recovery)	(0.02)	0.03	(0.05)	(167)%
Merger transaction costs	0.40	2.13	(1.73)	(81)%
General and administrative expense	2.31	3.19	(0.88)	(28)%
Operating expenses	$ 29.12	$ 29.77	$ (0.65)	(2)%
Operating expenses, excluding abandonment and impairment of unproved properties and unused commitments	$ 28.77	$ 26.59	$ 2.18	8 %

Lease operating expense. Our lease operating expense increased $117.6 million, or 224%, to $170.0 million for the year ended December 31, 2022 from $52.4 million for the year ended December 31, 2021, and increased 7% on an equivalent basis per Boe. Lease operating expense increased as a result of (i) the HighPoint, Extraction, and Crestone Peak mergers as well as the Bison Acquisition and (ii) increased activity and the impact of inflation in areas such as power, non-operated costs, and contract labor.

Midstream operating expense. Our midstream operating expense increased $14.5 million, or 83%, to $31.9 million for the year ended December 31, 2022 from $17.4 million for the year ended December 31, 2021, and decreased 40% on an equivalent basis per Boe. Midstream operating expense increased on an aggregate basis due to the acquisition of certain midstream assets through the HighPoint and Crestone Peak mergers. Conversely, while certain midstream operating expenses correlate to sales volumes, the majority of the costs, such as compression, are fixed and thereby result in a decrease in midstream operating expense per Boe period over period.

Gathering, transportation, and processing. Gathering, transportation, and processing expense increased $223.0 million, or 346%, to $287.5 million for the year ended December 31, 2022 from $64.5 million for the year ended December 31, 2021, and increased 47% on an equivalent basis per Boe. Sales volumes have a direct correlation to gathering, transportation, and processing expense and increased 204% during the comparable periods. Additionally, we are party to certain value-based percentage of proceeds sales contracts, which track solely with natural gas and NGL pricing and thereby have further contributed to the increase in gathering, transportation, and processing expense. Finally, we continually monitor for the best sales volumes outlet and thereby incurred increased gathering, transportation, and processing expense during the year ended December 31, 2022.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $240.6 million, or 369%, to $305.7 million for the year ended December 31, 2022 from $65.1 million for the year ended December 31, 2021, and increased 55% on an equivalent basis per Boe. Severance and ad valorem taxes primarily correlate to revenues, which increased by 309% for the year ended December 31, 2022 when compared to the same period in 2021. Additionally, through the Extraction and Crestone Peak mergers, we now operate in certain taxing districts with incrementally higher severance and ad valorem tax rates that are thereby contributing to the aggregate increase in severance and ad valorem taxes.

Depreciation, depletion, and amortization. Our depreciation, depletion, and amortization expense increased $589.5 million, or 260%, to $816.4 million for the year ended December 31, 2022 from $226.9 million for the year ended December 31, 2021, and increased 19% on an equivalent basis per Boe. The increase in depreciation, depletion, and amortization expense is the result of (i) a $3.7 billion increase in the depletable property basis on November 1, 2021 as a result of the Extraction and Crestone Peak mergers, (ii) a 204% increase in production between the comparable periods, and (iii) a $1.3 billion increase in the depletable property base during 2022 primarily due to development of oil and natural gas properties as well as the Bison Acquisition.

Abandonment and impairment of unproved properties. During the years ended December 31, 2022 and 2021, we incurred $18.0 million and $57.3 million, respectively, in abandonment and impairment of unproved properties due to the Company's assessment of its locations and replacement of non-core legacy locations with newly acquired locations.

Unused commitments. During the year ended December 31, 2022, we incurred $3.6 million in unused commitments primarily due to deficiency payments incurred under certain minimum volume crude oil and water commitments. During the year ended December 31, 2021, we incurred $7.7 million in unused commitments primarily due to the assumption of two firm natural gas pipeline transportation contracts in the HighPoint Merger to provide a guaranteed outlet for production from properties HighPoint had previously sold. Both firm transportation contracts, which expired on July 31, 2021, required us to pay transportation charges regardless of the amount of pipeline capacity utilized.

Merger transaction costs. During the years ended December 31, 2022 and 2021, we incurred $24.7 million and $43.6 million, respectively, in legal, advisor, and other costs associated with the HighPoint, Extraction, and Crestone Peak mergers as well as the Bison Acquisition. Merger transaction costs include $7.5 million and $1.6 million of severance payments associated with merger activity for the years ended December 31, 2022 and 2021, respectively.

General and administrative expense. Our general and administrative expense increased $78.4 million, or 120%, to $143.5 million for the year ended December 31, 2022 from $65.1 million for the year ended December 31, 2021, and decreased 28% on an equivalent basis per Boe. The primary drivers of the aggregate increase relate to an increase in salaries, benefits, and stock compensation expense associated with the HighPoint, Extraction, and Crestone Peak mergers and an increase in charitable contributions. General and administrative expense per Boe decreased due to oil equivalent sales volumes being 204% higher during the year ended December 31, 2022 as compared to the same period in 2021.

Derivative gain (loss). Our derivative loss for the years ended December 31, 2022 and December 31, 2021 of $335.2 million and $60.5 million, respectively, was due to settlement losses caused by market prices being higher than our current contracted hedge prices, partially offset by fair market value adjustments caused by market prices being lower relative to our future contracted hedge prices. Please refer to *Item 8, Note 9 - Derivatives* for additional discussion.

Interest expense. Our interest expense for the years ended December 31, 2022 and 2021 was $32.2 million and $9.7 million, respectively. Average debt outstanding for the years ended December 31, 2022 and 2021 was $435.5 million and $217.9 million, respectively. The components of interest expense for the periods presented are as follows (in thousands):

	Year Ended December 31,	
	2022	2021
Senior Notes	$ 22,521	$ 9,903
Credit Facility	115	2,019
Commitment and letter of credit fees under the Credit Facility	5,099	2,185
Amortization of deferred financing costs	4,464	1,890
Capitalized interest	—	(6,297)
Total interest expense, net	$ 32,199	$ 9,700

Income tax expense . Our income tax expense for the years ended December 31, 2022 and 2021 was $405.7 million and $72.9 million, resulting in an effective tax rate of 24.5% and 28.9% on pre-tax income, respectively. Our effective tax rate differs from the statutory United States federal income tax rate of 21% due to the effect of state income taxes, excess tax benefits and deficiencies on stock-based compensation awards, tax limitations on compensation of covered individuals, changes in valuation allowances, and other permanent differences. Please refer to *Item 8, Note 12 - Income Taxes* for additional discussion.

Liquidity and Capital Resources

The Company's primary sources of liquidity include cash flows from operating activities, available borrowing capacity under the Credit Facility, potential proceeds from equity and/or debt capital markets transactions, potential proceeds from sales of assets, and other sources. We may use our available liquidity for operating activities, working capital requirements, capital expenditures, acquisitions, the return of capital to shareholders, and for general corporate purposes.

Our primary source of cash flows from operating activities is the sale of oil, natural gas, and NGLs. As such, our cash flows are subject to significant volatility due to changes in commodity prices, as well as variations in our production volumes. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, the impact of inflation and monetary policy, weather, product distribution, refining and processing capacity, regulatory constraints, and other supply chain dynamics, among other factors.

As of December 31, 2022, our liquidity was $1.8 billion, consisting of cash on hand of $768.0 million and $987.9 million of available borrowing capacity on our Credit Facility. As of the date of filing of this report, the available borrowing capacity on our Credit Facility remained unchanged. Borrowing capacity under the Credit Facility is primarily based on the value assigned to the proved reserves attributable to our oil and natural gas interests. On April 20, 2022, the Company entered into an amendment to the Credit Agreement that increased the Company's borrowing base from $1.0 billion to $1.7 billion and the aggregate elected commitment amount from $800.0 million to $1.0 billion. On October 27, 2022, and as part of the regularly scheduled, semi-annual borrowing base redetermination under the Credit Facility, the Company's aggregate elected commitments of $1.0 billion were reaffirmed and borrowing base was increased from $1.7 billion to $1.85 billion.

The Credit Facility contains customary representations and various affirmative and negative covenants as well as certain financial covenants, including (a) a maximum ratio of the Company's consolidated indebtedness to earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash charges ("permitted net leverage ratio") of 3.00 to 1 and (b) a current ratio, inclusive of the unused commitments then available to be borrowed, to not be less than 1.00 to 1. The Company was in compliance with all covenants under the Credit Facility as of December 31, 2022, and through the filing of this report. Please refer to *Item 8, Note 5 - Long-Term Debt* for additional information.

Our material short-term cash requirements include: operating activities, working capital requirements, capital expenditures, commodity derivative liabilities, dividends, and payments of contractual obligations. Our material long-term cash requirements from various contractual and other obligations include: debt obligations and related interest payments, firm transportation and minimum volume agreements, taxes, asset retirement obligations, and operating leases. Please refer to *Item 8* for additional information. Our future capital requirements, both near-term and long-term, will depend on many factors, including, but not limited to, commodity prices, market conditions, our available liquidity and financing, acquisitions and divestitures of oil and gas properties, the availability of drilling rigs and completion crews, the cost of completion services, success of drilling programs, land and industry partner issues, weather delays, the acquisition of leases with drilling commitments, and other factors. We regularly consider which resources, including debt and equity financings, are available to meet our future financial obligations, planned capital expenditures, and liquidity requirements.

Funding for these requirements may be provided by any combination of the sources of liquidity outlined above. We expect our 2023 capital program to be funded by cash flows from operations. Although we cannot provide any assurance, based on our projected cash flows from operations, our cash on hand, and available borrowing capacity on our Credit Facility, we believe that we will have sufficient capital available to fund these requirements through the 12-month period following the filing of this report.

The following table summarizes our cash flows and other financial measures for the periods indicated (in thousands):

	Year Ended December 31,	
	2022	2021
Net cash provided by operating activities	$ 2,477,041	$ 274,599
Net cash provided by (used in) investing activities	(1,306,095)	73,547
Net cash used in financing activities	(657,368)	(118,435)
Cash, cash equivalents, and restricted cash	768,134	254,556
Acquisition of oil and natural gas properties	(377,923)	(1,250)
Exploration and development of oil and natural gas properties	(967,096)	(151,500)

Cash flows provided by operating activities

Net cash provided by operating activities increased by $2.2 billion to $2.5 billion in 2022 as compared to $274.6 million in 2021, which was attributable to our normal operating cycle. See *Results of Operations* above for more information on the factors driving these changes.

Cash flows provided by (used in) investing activities

Net cash used in investing activities of $1.3 billion during 2022 was primarily the result of the exploration and development of oil and natural gas properties of $967.1 million, acquisitions of oil and natural gas properties of $377.9 million that included the Bison Acquisition and the purchase additional working interests in certain Company-operated wells, partially offset by $44.3 million of cash acquired in the Bison Acquisition.

Net cash provided by investing activities of $73.5 million during 2021 was primarily the result of cash acquired in the HighPoint, Extraction, and Crestone Peak Mergers of $223.7 million, partially offset by the exploration and development of oil and natural gas properties of $151.5 million.

Cash flows used in financing activities

Net cash used in financing activities of $657.4 million during 2022 was primarily the result of dividends paid of $536.9 million, the redemption of our 7.5% Senior Notes for $100.0 million, and payments of employee tax withholdings in exchange for the return of common stock of $19.6 million.

Net cash used in financing activities of $118.4 million during 2021 was primarily the result of net payments made on the Credit Facility of $434.0 million that included the net payoff of the HighPoint credit facility of $154.0 million and the Crestone Peak credit facility of $280.0 million, dividends paid of $60.8 million, and deferred financing costs of $19.3 million. Partially offsetting these outflows were proceeds from the $400.0 million issuance of 5.0% Senior Notes.

Non-GAAP Financial Measures

Reconciliation of EBITDAX to Net Income

Adjusted EBITDAX represents earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash and non-recurring charges. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that we present because we believe it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to financial covenants under our Credit Facility based on adjusted EBITDAX ratios. Please refer to *Item 8, Note 5 - Long-Term Debt* for more information about financial covenants under our Credit Facility. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and natural gas exploration and production industry. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income, net cash provided by operating activities, or other profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies.

The following table presents a reconciliation of the GAAP financial measure of net income to the non-GAAP financial measure of Adjusted EBITDAX (in thousands):

	Year Ended December 31,	
	2022	2021
Net income	$ 1,248,080	$ 178,921
Exploration	6,981	7,937
Depreciation, depletion, and amortization	816,446	226,931
Abandonment and impairment of unproved properties	17,975	57,260
Stock-based compensation [1]	31,367	15,558
Non-recurring general and administrative expense [1]	18,037	2,609
Merger transaction costs	24,683	43,555
Unused commitments	3,641	7,692
Gain on property transactions, net	(15,880)	(1,932)
Interest expense	32,199	9,700
Derivative loss	335,160	60,510
Derivative cash settlement loss	(576,802)	(275,914)
Income tax expense	405,698	72,858
Adjusted EBITDAX	$ 2,347,585	$ 405,685

[1] Included as a portion of general and administrative expense in the accompanying consolidated statements of operations and comprehensive income (“statements of operations”).

Reconciliation of Free Cash Flow to Cash Provided by Operating Activities

Free cash flow is a supplemental non-GAAP financial measure that is calculated as net cash provided by operating activities before changes in current assets and liabilities and less exploration and development of oil and natural gas properties, changes in working capital related to capital expenditures, and purchases of carbon offsets. We believe that free cash flow provides additional information that may be useful to investors in evaluating our ability to generate cash from our existing oil and natural gas assets to fund future exploration and development activities and to return cash to shareholders. Free cash flow is a supplemental measure of liquidity and should not be viewed as a substitute for cash flows from operations because it excludes certain required cash expenditures.

The following table presents a reconciliation of the GAAP financial measure of net cash provided by operating activities to the non-GAAP financial measure of free cash flow (in thousands):

	Year Ended December 31,	
	2022	2021
Net cash provided by operating activities	$ 2,477,041	$ 274,599
Add back: changes in current assets and liabilities	(276,141)	61,573
Cash flow from operations before changes in operating assets and liabilities	2,200,900	336,172
Less: exploration and development of oil and natural gas properties	(967,096)	(151,500)
Less: changes in working capital related to capital expenditures	(7,679)	(128,977)
Less: purchases of carbon offsets	(7,298)	—
Free cash flow	$ 1,218,827	$ 55,695

Reconciliation of Proved Reserves PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Neither our PV-10 measure nor the Standardized Measure purports to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the GAAP financial measure of Standardized Measure to the non-GAAP financial measure of PV-10 as of the periods presented (in millions):

	December 31,		
	2022	2021	2020
PV-10	$ 9,834.3	$ 5,327.2	$ 437.1
Present value of future income taxes discounted at 10%	(1,906.8)	(915.1)	—
Standardized Measure	$ 7,927.5	$ 4,412.1	$ 437.1

Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these statements requires us to make certain assumptions, judgments, and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses, as well as the disclosure of contingent assets and liabilities and commitments as of the date of our financial statements. We evaluate our estimates and assumptions on an ongoing basis. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. We believe the following discussions of critical accounting estimates address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change. Our significant accounting policies are described in *Item 8, Note 1 - Summary of Significant Accounting Policies*.

Property and Equipment

Proved Properties. The Company accounts for its oil and gas properties under the successful efforts method of accounting. Under this method, the costs of development wells are capitalized to proved properties whether those wells are successful or unsuccessful. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities are depleted using the units-of-production method based on estimated proved developed reserves. Proved leasehold costs are also depleted; however, the units-of-production method is based on estimated total proved reserves. The computation of depletion expense takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. Because all of our proved properties are currently located in a single field, we apply depletion on a single field basis.

The Company assesses proved properties for impairment whenever events or circumstances indicate that their carrying value may not be recoverable. If carrying values exceed undiscounted future net cash flows, impairment is measured and recorded at fair value. Because there usually is a lack of quoted market prices for proved properties, the Company estimates the fair value using valuation techniques that convert estimated future net cash flows to a single discounted amount. Significant inputs and assumptions to this estimation include, but are not limited to, reserves volumes, future operating and development costs, future commodity prices, inclusive of applicable differentials, and a market-based weighted average cost of capital rate. The expected future cash flows used for impairment reviews include future production volumes associated with proved developed producing reserves and risk-adjusted proved undeveloped reserves, and when needed, probable and possible reserves.

Unproved Properties. Unproved properties consist of the costs to acquire undeveloped leases and are not subject to depletion until they are transferred to proved properties. Leasehold costs are transferred to proved properties on an ongoing basis as the properties to which they relate are evaluated and proved reserves established. Unproved properties are routinely evaluated for continued capitalization or impairment. On a quarterly basis, management assesses undeveloped leasehold costs for impairment by considering, among other things, remaining lease terms, future drilling plans and capital availability to execute such plans, commodity price outlooks, recent operational results, reservoir performance and geology, and estimated acreage value based on prices received for similar, recent acreage transactions by the Company or other market participants. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

Oil and Natural Gas Reserves. The successful efforts method of accounting outlined above inherently relies on the estimation of proved oil and natural gas reserves. Reserve quantities and the related estimates of future net cash flows are critical inputs in our calculation of units-of-production depletion and our evaluation of proved and unproved properties for impairment. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring the evaluation of available geological, geophysical, engineering and economic data to estimate underground accumulations of oil and natural gas that cannot be precisely measured. Consequently, the Company engages a third-party petroleum consultant to prepare our estimates of oil and natural gas reserves. Significant inputs and engineering assumptions used in developing the estimates of proved oil and natural gas reserves include reserves volumes, future operating and development costs, historical commodity prices, and the Company's ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking.

The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. We cannot predict the amounts or timing of such future revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of proved property.

Business Combinations

As part of our business strategy, we regularly pursue the acquisition of oil and natural gas properties. We utilize the acquisition method to account for acquisitions of businesses. Pursuant to this method, we allocate the cost of the acquisition, or purchase price, to assets acquired and liabilities assumed based on fair values as of the acquisition date.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant of these assumptions relate to the estimated fair values assigned to proved and unproved properties. Since sufficient market data was not available regarding the fair values of our acquired proved and unproved oil and gas properties, we engaged a third-party valuation expert to assist in preparing fair value estimates. We utilized a discounted cash flow approach, based on market participant assumptions. Significant judgments and assumptions are inherent in these estimates and include, among other things, reserve quantities and classification, pace of drilling plans, future commodity prices, future development and lease operating costs, and discount rates using a market-based weighted average cost of capital determined at the time of the acquisition. When estimating the fair value of unproved properties, additional risk-weighting adjustments are applied to probable and possible reserves.

Estimated fair values ascribed to assets acquired can have a significant impact on future results of operations presented in the Company's financial statements. For example, a higher fair value ascribed to a proved properties results in higher DD&A expense, which results in lower net income. As discussed above, estimated fair values assigned to proved and unproved properties are dependent on estimates of reserve quantities, future commodity prices, as well as development and operating costs. In the event that reserve quantities or future commodity prices are lower than those used as inputs to determine estimates of acquisition-date fair values, the likelihood increases that certain costs may be determined to not be recoverable.

In addition, we record deferred taxes for any differences between the assigned fair values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Effects of Inflation and Pricing

Inflation in the United States averaged 8.0% in 2022, 4.7% in 2021, and 1.2% in 2020. Although inflation increased significantly in 2022, inflation did not have a material impact on our results of operations for the period ended December 31, 2022, or for the periods ended December 31, 2021 and 2020.

The Company tends to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and natural gas prices increase drilling activity in our areas of operations. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations, depletion expense, impairment assessments of oil and gas properties, asset retirement obligations, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and the rate of return associated with the wells they develop and can hinder their ability to raise capital, borrow money, and retain personnel. With increased commodity prices and drilling activity, there have been increased costs associated with parts, materials, labor and other necessary drilling and completions related resources, including contracts for drilling and workover rigs and oilfield service companies.

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

Oil and Natural Gas Price Risk

Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil and natural gas, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels, local and global politics, and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations, and capital resources. If oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 1% and our PV-10 value as of December 31, 2022 would decrease by approximately 13% or $1.3 billion. If oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 1% and our PV-10 value as of December 31, 2022 would increase by approximately 13% or $1.3 billion.

PV-10 is a non-GAAP financial measure. Please refer to *Non-GAAP Financial Measures* under *Part I, Item 7* for management's discussion of this non-GAAP financial measure.

Commodity Price Derivative Contracts

Our primary commodity risk management objective is to protect the Company's balance sheet. We periodically enter into derivative contracts for oil, natural gas, and natural gas liquids using NYMEX futures or over-the-counter derivative financial instruments. The types of derivative instruments that we use include swaps, collars, and puts.

Upon settlement of the contract(s), if the relevant market commodity price exceeds our contracted swap price, or the collar's ceiling strike price, we are required to pay our counterparty the difference for the volume of production associated with the contract. Generally, this payment is made up to 15 business days prior to the receipt of cash payments from our customers. This could have an adverse impact on our cash flows for the period between derivative settlements and payments for revenue earned.

While we may reduce the potential negative impact of lower commodity prices, we may also be prevented from realizing the benefits of favorable price changes in the physical market. For the derivatives outstanding at December 31, 2022, a hypothetical upward or downward shift of 10% in the forward curve for the related indices would increase our derivative loss by $20.7 million or decrease it by $20.4 million, respectively.

Please refer to the *Derivative Activities* section of *Part I, Item 1* for summary derivative activity tables.

Interest Rates

At both December 31, 2022 and on the filing date of this report, we had a zero balance on our Credit Facility. Borrowings under our Credit Facility bear interest at a fluctuating rate that is tied to an Alternate Base Rate or Secured Overnight Financing Rate, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flows. As of December 31, 2022 and through the filing date of this report, the Company was in compliance with all financial and non-financial covenants.

Counterparty and Customer Credit Risk

In connection with our derivative activity, we have exposure to financial institutions in the form of derivative transactions. As of December 31, 2022, our derivative contracts have been executed with 7 counterparties, all of which are members of the Credit Facility lender group and have investment grade credit ratings. However, if our counterparties fail to perform their obligations under the contracts, we could suffer financial loss.

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

Marketability of Our Production

The marketability of our production depends in part upon the availability, proximity, and capacity of third-party refineries, access to regional trucking, pipeline and rail infrastructure, natural gas gathering systems, and processing facilities. We deliver crude oil and natural gas produced through trucking services, pipelines, and rail facilities that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, weather, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Civitas Resources, Inc.

Opinion on the Financial Statements

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

We have also 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 February 22, 2023, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matter

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

Proved Oil and Gas Properties and Depletion — Estimated Proved Reserves — Refer to Note 1 to the consolidated financial statements

Critical Audit Matter Description

The Company's capitalized costs of proved oil and gas properties are depleted using the units of production method based on estimated proved reserves. The development of the Company's estimated proved reserve volumes requires management to make significant estimates and assumptions, including the Company's ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking. The Company engages an independent reserve engineer to estimate oil and natural gas quantities using these estimates and assumptions and engineering data. Changes in these assumptions could materially affect the estimated quantities of the Company's reserves. The proved oil and gas properties, net balance was $5,560.2 million, as of December 31, 2022. Depletion expense was $773.5 million for the year ended December 31, 2022.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's estimated proved reserve quantities, including management's estimates and assumptions related to converting proved undeveloped reserves to producing properties within five years, required a high degree of auditor judgment and an increased extent of effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to proved reserve quantities and converting proved undeveloped reserves to producing properties within five years included the following, among others:

We tested the design, implementation, and operating effectiveness of controls related to the Company's estimation of proved reserves, including controls relating to the five-year conversion plan.

We evaluated the Company's estimated proved reserves and reasonableness of management's five-year conversion plan by:

- Comparing the Company's reserve estimated future production to historical production volumes.
- Assessing the reasonableness of the production volume decline curves by comparing to historical decline curve estimates.
- Comparing the forecasts to historical conversions of proved undeveloped oil and gas reserves into proved developed oil and gas reserves.
- Comparing the forecasts to the Company's drill plan and the availability of capital relative to the drill plan.
- Reviewing internal communications to management and the Board of Directors.
- Comparing the forecasts to forecasted information included in Company press releases as well as in analyst and industry reports for the Company and certain of its peer companies.

We evaluated the experience, qualifications and objectivity of management's expert, an independent reserve engineering firm, including the methodologies used to estimate proved reserve quantities.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 22, 2023

We have served as the Company's auditor since 2019.

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)

	As of December 31, 2022	As of December 31, 2021
ASSETS		
Current assets:		
Cash and cash equivalents	$ 768,032	$ 254,454
Accounts receivable, net:		
Oil and natural gas sales	343,500	362,262
Joint interest and other	135,816	66,390
Derivative assets	2,490	3,393
Prepaid income taxes	29,604	—
Prepaid expenses and other	48,988	33,438
Total current assets	1,328,430	719,937
Property and equipment (successful efforts method):		
Proved properties	6,774,635	5,457,213
Less: accumulated depreciation, depletion, and amortization	(1,214,484)	(430,201)
Total proved properties, net	5,560,151	5,027,012
Unproved properties	593,971	688,895
Wells in progress	407,351	177,296
Other property and equipment, net of accumulated depreciation of $7,329 in 2022 and $4,742 in 2021	49,632	51,639
Total property and equipment, net	6,611,105	5,944,842
Long-term derivative assets	794	—
Right-of-use assets	24,125	39,885
Deferred income tax assets	—	22,284
Other noncurrent assets	6,945	14,085
Total assets	$ 7,971,399	$ 6,741,033
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 295,297	$ 246,188
Production taxes payable	258,932	144,408
Oil and natural gas revenue distribution payable	538,343	466,233
Lease liability	13,464	18,873
Derivative liability	46,334	219,804
Asset retirement obligations	25,557	24,000
Total current liabilities	1,177,927	1,119,506
Long-term liabilities:		
Senior notes	393,293	491,710
Lease liability	11,324	21,398
Ad valorem taxes	412,650	232,147
Derivative liability	17,199	19,959
Deferred income tax liabilities	319,618	—
Asset retirement obligations	265,469	201,315
Total liabilities	2,597,480	2,086,035
Commitments and contingencies (Note 6)		
Stockholders' equity:		
Preferred stock, $.01 par value, 25,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 225,000,000 shares authorized, 85,120,287 and 84,572,846 issued and outstanding as of December 31, 2022 and 2021, respectively	4,918	4,912
Additional paid-in capital	4,211,197	4,199,108
Retained earnings	1,157,804	450,978
Total stockholders' equity	5,373,919	4,654,998
Total liabilities and stockholders' equity	$ 7,971,399	$ 6,741,033

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(in thousands, except per share amounts)

	Year Ended December 31, 2022	2021	2020
Operating net revenues:			
Oil and natural gas sales	$ 3,791,398	$ 930,614	$ 218,090
Operating expenses:			
Lease operating expense	169,986	52,391	21,957
Midstream operating expense	31,944	17,426	14,948
Gathering, transportation, and processing	287,474	64,507	16,932
Severance and ad valorem taxes	305,701	65,113	3,787
Exploration	6,981	7,937	596
Depreciation, depletion, and amortization	816,446	226,931	91,242
Abandonment and impairment of unproved properties	17,975	57,260	37,343
Unused commitments	3,641	7,692	—
Bad debt expense (recovery)	(950)	607	818
Merger transaction costs	24,683	43,555	6,676
General and administrative expense (including $31,367, $15,558, and $6,156, respectively, of stock-based compensation)	143,477	65,132	34,936
Total operating expenses	1,807,358	608,551	229,235
Other income (expense):			
Derivative gain (loss)	(335,160)	(60,510)	53,462
Interest expense	(32,199)	(9,700)	(2,045)
Gain (loss) on property transactions, net	15,880	1,932	(1,398)
Other income (expense)	21,217	(2,006)	4,107
Total other income (expense)	(330,262)	(70,284)	54,126
Income from operations before income taxes	1,653,778	251,779	42,981
Income tax (expense) benefit	(405,698)	(72,858)	60,547
Net income	$ 1,248,080	$ 178,921	$ 103,528
Comprehensive income	$ 1,248,080	$ 178,921	$ 103,528
Net income per common share:			
Basic	$ 14.68	$ 4.82	$ 4.98
Diluted	$ 14.58	$ 4.74	$ 4.95
Weighted-average common shares outstanding			
Basic	85,005	37,155	20,774
Diluted	85,604	37,746	20,912

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except per share amounts)

	Common Stock		Additional Paid-In	Accumulated	
	Shares	Amount	Capital	Earnings	Total
Balances, December 31, 2019	20,643,738	$ 4,284	$ 702,173	$ 230,233	$ 936,690
Restricted common stock issued	259,995	—	—	—	—
Restricted stock used for tax withholdings	(64,506)	(2)	(1,120)	—	(1,122)
Stock-based compensation	—	—	6,156	—	6,156
Net income	—	—	—	103,528	103,528
Balances, December 31, 2020	20,839,227	4,282	707,209	333,761	1,045,252
Issuance pursuant to acquisition	63,397,194	634	3,403,216	—	3,403,850
Restricted common stock issued	415,856	—	—	—	—
Restricted stock used for tax withholdings	(125,740)	(4)	(5,923)	—	(5,927)
Exercise of stock options	46,309	—	1,585	—	1,585
Stock-based compensation	—	—	15,558	—	15,558
Issuance of warrants	—	—	77,463	—	77,463
Cash dividends, $1.16 per share	—	—	—	(61,704)	(61,704)
Net income	—	—	—	178,921	178,921
Balances, December 31, 2021	84,572,846	4,912	4,199,108	450,978	4,654,998
Restricted common stock issued	855,073	9	—	—	9
Restricted stock used for tax withholdings	(316,793)	(3)	(19,586)	—	(19,589)
Exercise of stock options	9,161	—	308	—	308
Stock-based compensation	—	—	31,367	—	31,367
Cash dividends, $6.29 per share	—	—	—	(541,254)	(541,254)
Net income	—	—	—	1,248,080	1,248,080
Balances, December 31, 2022	85,120,287	$ 4,918	$ 4,211,197	$ 1,157,804	$ 5,373,919

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2022	2021	2020
Cash flows from operating activities:			
Net income	$ 1,248,080	$ 178,921	$ 103,528
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, and amortization	816,446	226,931	91,242
Deferred income tax expense (benefit)	337,502	72,858	(60,520)
Abandonment and impairment of unproved properties	17,975	57,260	37,343
Stock-based compensation	31,367	15,558	6,156
Amortization of deferred financing costs	4,464	1,890	864
Derivative (gain) loss	335,160	60,510	(53,462)
Derivative cash settlement gain (loss)	(576,802)	(275,914)	49,406
(Gain) loss on property transactions, net	(15,880)	(1,932)	1,398
Other	2,588	90	(186)
Changes in current assets and liabilities:			
Accounts receivable, net	(941)	(100,881)	24,945
Prepaid expenses and other assets	(34,025)	(3,338)	3,352
Accounts payable and accrued liabilities	335,563	47,510	(41,278)
Settlement of asset retirement obligations	(24,456)	(4,864)	(3,992)
Net cash provided by operating activities	2,477,041	274,599	158,796
Cash flows from investing activities:			
Acquisition of oil and natural gas properties	(377,923)	(1,250)	(3,210)
Cash acquired	44,310	223,692	—
Exploration and development of oil and natural gas properties	(967,096)	(151,500)	(60,149)
Proceeds from sale of oil and natural gas properties	2,355	—	—
Purchases of carbon offsets	(7,298)	—	—
Proceeds from (additions to) other property and equipment	(579)	2,393	(440)
Other	136	212	—
Net cash provided by (used in) investing activities	(1,306,095)	73,547	(63,799)
Cash flows from financing activities:			
Proceeds from credit facility	100,000	155,000	45,000
Payments to credit facility	(100,000)	(589,000)	(125,000)
Proceeds from issuance of senior notes	—	400,000	—
Redemption of senior notes	(100,000)	—	—
Proceeds from exercise of stock options	308	1,585	—
Dividends paid	(536,922)	(60,780)	—
Payment of employee tax withholdings in exchange for the return of common stock	(19,580)	(5,927)	(1,122)
Deferred financing costs	(1,174)	(19,292)	(23)
Other	—	(21)	(102)
Net cash used in financing activities	(657,368)	(118,435)	(81,247)
Net change in cash, cash equivalents, and restricted cash	513,578	229,711	13,750
Cash, cash equivalents, and restricted cash:			
Beginning of period [1]	254,556	24,845	11,095
End of period [1]	$ 768,134	$ 254,556	$ 24,845

[1] Includes $0.1 million of restricted cash and consists of funds for road maintenance and repairs that is presented in other noncurrent assets within the accompanying balance sheets.
Please refer to *Note 14* for *Supplemental Disclosures of Cash Flow Information.*

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

CIVITAS RESOURCES, INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations

Civitas is an independent exploration and production company focused on the acquisition, development, and production of oil and associated liquids-rich natural gas in the Rocky Mountain region, primarily in the DJ Basin of Colorado.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company and have been prepared in accordance with GAAP, the instructions to Form 10-K, and Regulation S-X. All significant intercompany balances and transactions have been eliminated in consolidation. Additionally, certain prior period amounts have been reclassified to conform to current period presentation in the accompanying financial statements. During the current year, the Company is presenting inventory of oilfield equipment within prepaid expenses and other on the accompanying balance sheets. Accordingly, prior year amounts have been reclassified from inventory of oilfield equipment to prepaid expenses and other assets to conform to current year presentation. In connection with the preparation of the accompanying consolidated financial statements, the Company evaluated events subsequent to the balance sheet date of December 31, 2022, through the filing date of this report.

Use of Estimates

The preparation of the consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities and commitments as of the date of our financial statements. Actual results could differ from those estimates.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the acquisition, development, and production of oil and associated liquids-rich natural gas. All of the Company’s operations are conducted in the continental United States.

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturity dates of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximate fair value due to the short-term nature of these instruments. The Company maintained cash balances in excess of federal deposit insurance limits as of December 31, 2022 and 2021, potentially subjecting the Company to a concentration of credit risk. To mitigate this risk, we maintain our cash and cash equivalents in the form of money market deposit and checking accounts with financial institutions that we believe are creditworthy and are also lenders under our Credit Facility.

Accounts Receivable

The Company’s accounts receivable primarily consists of receivables due from purchasers of the Company’s oil, natural gas, and NGL production and from joint interest owners on properties the Company operates. The Company is exposed to credit risk in the event of nonpayment by the purchasers of its production and joint interest owners, nearly all of which are concentrated in energy-related industries. The Company continuously evaluates the creditworthiness of its purchasers and joint interest owners. Generally, the Company’s oil, natural gas, and NGLs receivables are collected within one to two months. For receivables due from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. The Company has historically experienced minimal bad debts.

The Company does not believe the loss of any single purchaser of its production would materially impact its financial position or results of operations, as oil, natural gas, and NGLs are products with well-established and highly liquid markets. For the periods presented below, the following purchasers of the Company's production accounted for more than 10% of the Company's revenue as follows:

	Year Ended December 31,		
	2022	2021	2020
Customer A	50 %	43 %	77 %
Customer B	12 %	2 %	— %
Customer C	10 %	13 %	9 %
Customer D	6 %	15 %	— %

Property and Equipment

Proved Properties. The Company accounts for its oil and natural gas properties under the successful efforts method of accounting. Under this method, the costs of development wells are capitalized to proved properties whether those wells are successful or unsuccessful. Capitalized drilling and completion costs, including lease and well equipment, intangible development costs, and operational support facilities, are depleted using the units-of-production method based on estimated proved developed reserves. Proved leasehold costs are also depleted; however, the units-of-production method is based on estimated total proved reserves. The computation of depletion expense takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. Because all of our proved properties are currently located in a single basin, we apply depletion on a single-basin basis. During the years ended December 31, 2022, 2021, and 2020, the Company incurred depletion expense of $773.5 million, $212.5 million, and $82.6 million, respectively.

The Company assesses proved properties for impairment whenever events or circumstances indicate that their carrying value may not be recoverable. If carrying values exceed undiscounted future net cash flows, impairment is measured and recorded at fair value. Due to a lack of quoted market prices for proved properties, the Company estimates the fair value using valuation techniques that convert estimated future net cash flows to a single discounted amount. Significant inputs and assumptions to this estimation include, but are not limited to, reserves volumes, future operating and development costs, future commodity prices, inclusive of applicable differentials, and a market-based weighted average cost of capital rate. The expected future cash flows used for impairment reviews include future production volumes associated with proved developed producing reserves and risk-adjusted proved undeveloped reserves as well as risk-adjusted probable and possible reserves, as applicable.

The partial sale of a proved property within an existing field is accounted for as a normal retirement and no net gain or loss on divestiture activity is recognized as long as such treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A net gain or loss on divestiture activity is recognized in the accompanying statements of operations for all other sales of proved properties.

As of December 31, 2022 and 2021, the net book value of the Company's midstream assets in the accompanying balance sheets was $326.8 million and $276.1 million, respectively. Depreciation on the Company's midstream assets is calculated using the straight-line method over the estimated useful lives of the assets and properties they serve, which is approximately 30 years.

Unproved Properties. Unproved properties consist of the costs to acquire undeveloped leases and are not subject to depletion until they are transferred to proved properties. Leasehold costs are transferred to proved properties on an ongoing basis as the properties to which they relate are evaluated and proved reserves established.

Additional costs not subject to depletion include costs associated with development wells in progress or awaiting completion at year-end. These costs are transferred into costs subject to depletion on an ongoing basis as these wells are completed and proved reserves are established or confirmed.

Unproved properties are routinely evaluated for continued capitalization or impairment. On a quarterly basis, management assesses undeveloped leasehold costs for impairment by considering, among other things, remaining lease terms, future drilling plans and capital availability to execute such plans, commodity price outlooks, recent operational results, reservoir performance and geology, and estimated acreage value based on prices received for similar, recent acreage transactions by the Company or other market participants. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

The partial sale of unproved property is accounted for as a recovery of cost when there is uncertainty of the ultimate recovery of the cost applicable to the interest retained.

Exploratory. Exploratory geological and geophysical, including exploratory seismic studies, and the costs of carrying and retaining unproved acreage are expensed as incurred. Under the successful efforts method of accounting, exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are found, exploratory well costs will be capitalized as proved properties. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in the cash flows from investing activities section as part of exploration and development of oil and natural gas properties within the accompanying statements of cash flows.

Oil and Natural Gas Reserves. The successful efforts method of accounting inherently relies on the estimation of proved oil and natural gas reserves. Reserve quantities and the related estimates of future net cash flows are critical inputs in our calculation of units-of-production depletion and our evaluation of proved and unproved properties for impairment. The process of estimating and evaluating crude oil and natural gas reserves is complex, requiring the evaluation of available geological, geophysical, engineering, and economic data to estimate underground accumulations of oil and natural gas that cannot be precisely measured. Consequently, the Company engages third-party independent reserve engineers Ryder Scott to prepare our estimates of oil and natural gas reserves. Significant inputs and engineering assumptions used in developing the estimates of proved oil and natural gas reserves include reserves volumes, future operating and development costs, historical commodity prices, and the Company’s ability to convert proved undeveloped reserves to producing properties within five years of their initial proved booking.

The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history, and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. We cannot predict the amounts or timing of such future revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of proved property.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Cost of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed as incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, which range from three to 25 years.

Leases

The Company determines if an arrangement is representative of a lease at contract inception. Right-of-use assets represent our right to use the underlying assets for the lease term and the corresponding lease liabilities represent our obligations to make lease payments arising from the leases. Right-of-use assets and lease liabilities are recognized at the lease commencement date based on the present value of the lease payments over the lease term. When evaluating a contract, the Company applies certain judgments to determine, among other factors, lease classification as either operating or financing, lease term, and discount rate. The terms of certain of our leases include options to extend or terminate the lease, only when we can ascertain that it is reasonably certain we will exercise that option, as well as evergreen periods for which the penalties associated with termination are considered to be significant. Leases with an initial term of one year or less are not recorded on the accompanying balance sheets. As the Company does not have any leases with an implicit interest rate that can be readily determined, we utilize our incremental borrowing rate based on information available at the lease commencement date in determining the present value of lease payments. We determine our incremental borrowing rate at the lease commencement date using our Credit Facility benchmark rate and make adjustments for facility utilization and lease term. Subsequent measurement, as well as presentation of expenses and cash flows, is dependent upon the classification of the lease as either an operating or finance lease. Please refer to *Note 13 - Leases* for additional discussion.

Carbon Offsets and Renewable Energy Credits

The Company periodically purchases carbon offsets and renewable energy credits as a means to offset carbon emissions generated by its operations and purchased electricity that could not otherwise be reduced or eliminated. Commensurate with their use, purchased carbon offsets and renewable energy credits are initially capitalized at cost as an intangible asset within other noncurrent assets on the accompanying balance sheets. Subsequently, capitalized carbon offsets and renewable energy credits are expensed when applied to the Company's carbon emissions through depletion, depreciation, and amortization expense on the accompanying statements of operations. Purchased carbon offsets and renewable energy credits expected to be utilized within the next 12 months are presented as short-term within prepaid expenses and other on the accompanying balance sheets.

Deferred Financing Costs

Deferred financing costs include origination, legal, and other fees incurred to issue debt or amend existing credit facilities. Deferred financing costs related to the Credit Facility are capitalized to prepaid expenses and other and other noncurrent assets on the accompanying balance sheets and amortized to interest expense, net on the accompanying statements of operations on a straight-line basis over the life of the Credit Facility. Deferred financing costs related to senior notes are capitalized within senior notes on the accompanying balance sheets and amortized to interest expense, net on the accompanying statements of operations using the effective interest method over the life of the respective borrowings.

Asset Retirement Obligations

The Company recognizes an asset retirement obligation at fair value based on the present value of costs expected to be incurred in connection with the future abandonment of its oil and natural gas properties, including wells and facilities, in accordance with applicable regulatory requirements. This obligation, and the corresponding capitalized cost recorded to proved properties, is recorded at the time assets are acquired, a well is completed and begins production, or a facility is constructed. The Company recognizes a periodic expense in connection with the accretion of the discounted asset retirement obligation over the remaining estimated economic lives of the respective long-lived assets. The accretion expense is recorded as a component of depreciation, depletion, and amortization in our accompanying statements of operations. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the corresponding capitalized cost recorded to proved properties.

The recognition of an asset retirement obligation requires management to make various assumptions informed by historical experience and applicable regulatory requirements including estimated plugging and abandonment costs, economic lives, inflation rates, and the Company's credit-adjusted risk-free rate.

Cash paid to settle asset retirement obligations is included in the cash flows from operating activities section of the accompanying statements of cash flows. Please refer to *Note 10 - Asset Retirement Obligations* for a reconciliation of the Company's total asset retirement obligation liability as of December 31, 2022 and 2021.

Derivatives

The Company periodically enters into commodity price derivative instruments to mitigate a portion of its exposure to potentially adverse market changes in commodity prices for its expected future oil and natural gas production and the associated impact on cash flows. These instruments typically include commodity price swaps and collars. The oil instruments are indexed to NYMEX WTI prices, and natural gas instruments are indexed to NYMEX HH and CIG prices, all of which have a high degree of historical correlation with actual prices received by the Company, before differentials. As of December 31, 2022, all derivative counterparties were members of the Credit Facility lender group and all commodity derivative contracts are entered into for other-than-trading purposes. The Company does not designate its commodity derivative contracts as hedging instruments.

Commodity price derivative instruments are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities, with the exception of derivative instruments that meet the "normal purchase normal sale" exclusion. The Company measures the fair value of its commodity price derivative instruments based upon a pricing model that utilizes market-based inputs, including, but not limited to, contractual price of the underlying position, current market prices, crude oil and natural gas forward curves, discount rates, volatility factors, and nonperformance risk. Changes in the fair value of the Company's commodity price derivative instruments are recorded in the accompanying statements of operations as they occur.

As of December 31, 2022 and 2021, all derivative instruments held by the Company were subject to master netting arrangements with various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for transactions that settle on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company's accounting policy is to not offset these positions in its accompanying balance sheets.

Derivative (gain) loss as well as derivative cash settlement gain (loss) are included within the cash flows from operating activities section of the accompanying statements of cash flows. Please refer to *Note 9 - Derivatives* for additional discussion.

Revenue Recognition

The Company recognizes revenue from the sale of produced oil, natural gas, and NGL at the point in time when control of produced oil, natural gas, or NGL volumes transfer to the purchaser, which may differ depending on the applicable contractual terms. The Company considers the transfer of control to have occurred when the purchaser has the ability to direct the use of, and obtain substantially all of the remaining benefits from, the oil, natural gas, or NGL production. Transfer of control dictates the presentation of gathering, transportation, and processing expenses within the accompanying statements of operations. Gathering, transportation, and processing expenses incurred by the Company prior to the transfer of control are recorded gross within gathering, transportation, and processing in the accompanying statements of operations. Conversely, gathering, transportation, and processing expenses incurred by the Company subsequent to the transfer of control are recorded net within oil, natural gas, and NGL sales on the accompanying statements of operations.

Oil sales. Under the Company's crude purchase and marketing contracts, the Company typically delivers production at the wellhead, or other contractually agreed-upon delivery points, and collects an agreed-upon index price, net of pricing differentials. In this scenario, the Company recognizes revenue when control of its oil production transfers to the purchaser at the wellhead, or other contractually agreed-upon delivery point, at the net contracted price received.

Natural gas and NGL sales. Under the Company's natural gas processing contracts, the Company delivers natural gas to a midstream processing provider at the wellhead, inlet of the midstream processing provider's system, or other contractually agreed-upon delivery points. The delivery points are specified within each contract, and the point at which control transfers varies between the inlet and tailgate of the midstream processing facility. The midstream processing provider gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of NGLs and residue gas.

For the contracts where the Company maintains control through the tailgate of the midstream processing facility, the Company recognizes revenue on a gross basis, with gathering, transportation, and processing fees presented as an expense in the accompanying statements of operations. Alternatively, for those contracts where the Company relinquishes control at the inlet of the midstream processing facility, the Company recognizes natural gas and NGL revenues based on the contracted amount of the proceeds received from the midstream processing entity and, as a result, the Company recognizes revenue on a net basis.

In certain natural gas processing agreements, the Company may elect to take its residue gas and/or NGLs in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, the Company delivers product to the third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the third-party purchaser. In this scenario, the Company recognizes revenue when the control transfers to the third-party purchaser at the delivery point based on the index price received from the third-party purchaser. The gathering and processing expense attributable to the natural gas processing contracts, as well as any transportation expense incurred to deliver the product to the third-party purchaser, are presented as gathering, transportation, and processing expense in the consolidated statements of operations.

The Company records revenue in the month production is delivered and control is transferred to the purchaser. However, settlement statements and payment may not be received for 30 to 60 days after the date production is delivered and control is transferred. Until such time settlement statements and payment are received, the Company records a revenue accrual based on, amongst other factors, an estimate of the volumes delivered at estimated prices as determined by the applicable contractual terms. The Company records the differences between its estimates and the actual amounts received for product sales in the month in which payment is received from the purchaser. Please refer to *Note 3 - Revenue Recognition* for additional discussion.

Stock-Based Compensation

The Company recognizes stock-based compensation based on the grant-date fair value of the equity instruments awarded. Stock-based compensation expense is recognized in the financial statements on a straight-line basis over the requisite service period for the entire award. The Company accounts for forfeitures of stock-based compensation awards as they occur. Please refer to *Note 7 - Stock-Based Compensation* for additional discussion.

Income Taxes

The Company accounts for income taxes under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the balance sheet or tax returns. Deferred income tax assets and liabilities are measured using enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. If we determine that it is more-likely-than-not that some portion or all of the deferred income tax assets will not be realized, a valuation allowance is recorded, thereby reducing the deferred income tax assets to what is considered to be realizable.

The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The Company's policy is to recognize interest and penalties related to uncertain tax positions in income tax expense. There were no uncertain tax positions during any period presented.

The tax returns for 2021, 2020, and 2019 are still subject to audit by the Internal Revenue Service. Please refer to *Note 12 - Income Taxes* for additional discussion.

Earnings Per Share

The Company uses the treasury stock method to determine the effect of potentially dilutive instruments. Please refer to *Note 11 - Earnings Per Share* for additional discussion.

Acreage Exchanges

From time to time, we enter into acreage exchanges in order to consolidate our core acreage positions, enabling us to have more control over the timing of development activities, achieve higher working interests and provide us the ability to drill longer lateral length wells within those core areas. We account for our nonmonetary acreage exchanges in accordance with the guidance prescribed by *Accounting Standards Codification (*"*ASC*"*) 845, Nonmonetary Transactions*. For those exchanges that lack commercial substance, we record the acreage received at the net carrying value of the acreage surrendered to obtain it. For those acreage exchanges that are deemed to have commercial substance, we record the acreage received at fair value, with a related gain or loss recognized within gain (loss) on property transactions, net in the accompanying statements of operations, in accordance with *ASC 820, Fair Value Measurement*.

Business Combinations

As part of our business strategy, we regularly pursue the acquisition of oil and natural gas properties. We utilize the acquisition method to account for acquisitions of businesses. Pursuant to this method, we allocate the cost of the acquisition, or purchase price, to assets acquired and liabilities assumed based on fair values as of the acquisition date. Please refer to *Note 2 - Acquisitions and Divestitures* for additional discussion.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, accounts receivables, and accounts payable and are carried at cost, which approximates fair value due to the short-term maturity of these instruments. As discussed above, the Company's commodity price derivative instruments are recorded at fair value. The Company's Senior Notes, as defined in *Note 5 – Long-Term Debt*, are recorded at cost, net of any unamortized deferred financing costs, and their respective fair values are disclosed in *Note 8 – Fair Value Measurement*s. The recorded value of the Company's Credit Facility, as defined in *Note 5 – Long-Term Debt*, approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The Company's warrants were recorded at fair value upon issuance, with no recurring fair value measurement required.

Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments. Please refer to *Note 8 - Fair Value Measurement*s for additional discussion.

Recently Issued and Adopted Accounting Standards

There are no accounting standards applicable to the Company that would have a material effect on the Company's financial statements and disclosures that have been issued but not yet adopted by the Company as of December 31, 2022, and through the filing date of this report.

NOTE 2 - ACQUISITIONS AND DIVESTITURES

All mergers and acquisitions disclosed were accounted for under the acquisition method of accounting for business combinations. Accordingly, we conducted assessments of the net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values. Associated transaction and integration costs were expensed as incurred. The fair value measurements of assets acquired and liabilities assumed were based on inputs that are not observable in the market, and therefore represent Level 3 inputs. Please refer to *Note 8 - Fair Value Measurements* for additional discussion regarding the various levels within the fair value hierarchy. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of proved properties include estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, and a market-based weighted-average cost of capital. These inputs required significant judgments and estimates by management at the time of the valuation.

HighPoint Merger

On April 1, 2021, Civitas acquired HighPoint Resources Corporation ("HighPoint"), pursuant to the terms of HighPoint's prepackaged plan of reorganization under Chapter 11 of the United States Bankruptcy Code (the "Prepackaged Plan") (the "HighPoint Merger"). Pursuant to the Prepackaged Plan, each share of common stock of HighPoint issued and outstanding was converted into 0.11464 shares of common stock of Civitas ("Civitas Common Stock"). As a result, Civitas issued 488.0 thousand shares of Civitas Common Stock to former HighPoint stockholders.

Concurrently with the HighPoint Merger and pursuant to the Prepackaged Plan, in exchange for the aggregate principal amount outstanding of HighPoint's senior notes, Civitas issued an aggregate of (i) 9.3 million shares of Civitas Common Stock and (ii) $100.0 million aggregate principal amount of 7.5% Senior Notes due 2026 ("7.5% Senior Notes"). Please refer to *Note 5 - Long-Term Debt* for further discussion of the 7.5% Senior Notes, which have since been redeemed in full.

The purchase price allocation was finalized as of the first quarter of 2022. The following tables present the merger consideration and final purchase price allocation of the assets acquired and the liabilities assumed in the HighPoint Merger:

Merger Consideration (in thousands, except per share amount)		
Shares of Civitas Common Stock issued to existing holders of HighPoint common stock [1]		488
Shares of Civitas Common Stock issued to existing holders of HighPoint senior notes		9,314
Total additional shares of Civitas Common Stock issued as merger consideration		9,802
Closing price per share of Civitas Common Stock [2]	$	38.25
Merger consideration paid in shares of Civitas Common Stock	$	374,933
Aggregate principal amount of the 7.5% Senior Notes		100,000
Total merger consideration	$	474,933

(1) Based on the number of shares of common stock of HighPoint issued and outstanding as of April 1, 2021 and the conversion ratio of 0.11464 per share of Civitas Common Stock.

(2) Based on the closing stock price of Civitas Common Stock on April 1, 2021.

Purchase Price Allocation (in thousands)		
Assets Acquired		
Cash and cash equivalents	$	49,827
Accounts receivable - oil, natural gas sales, and NGL sales		26,343
Accounts receivable - joint interest and other		9,161
Prepaid expenses and other		3,608
Inventory of oilfield equipment		4,688
Proved properties		539,820
Other property and equipment		2,769
Right-of-use assets		4,010
Deferred income tax assets		110,513
Other noncurrent assets		797
Total assets acquired	$	751,536
Liabilities Assumed		
Accounts payable and accrued expenses	$	51,088
Oil and natural gas revenue distribution payable		20,786
Lease liability		4,010
Derivative liability		18,500
Current portion of long-term debt		154,000
Ad valorem taxes		3,746
Asset retirement obligations		24,473
Total liabilities assumed		276,603
Net assets acquired	$	474,933

The valuation of proved oil and natural gas properties for the HighPoint Merger applied a market-based weighted-average cost of capital rate of approximately 13%.

Extraction Merger

On November 1, 2021, Civitas completed its merger with Extraction Oil & Gas, Inc. (“Extraction”), pursuant to the terms of the related Agreement and Plan of Merger (the “Extraction Merger Agreement”) (the “Extraction Merger”). Pursuant to the Extraction Merger Agreement, each share of common stock of Extraction issued and outstanding was converted into 1.1711 shares of Civitas Common Stock (the “Extraction Exchange Ratio”). As a result, Civitas issued 31.1 million shares of Civitas Common Stock to former Extraction stockholders.

Additionally, each unvested award of restricted stock units issued pursuant to Extraction’s 2021 Long Term Incentive Plan (the “Extraction Equity Plan”) was assumed by Civitas and converted into a number of restricted stock units with respect to shares of Civitas Common Stock (such restricted stock unit, a “Converted RSU”) using the Extraction Exchange Ratio. Each Converted RSU continued to be governed by the same terms and conditions that were applicable immediately prior to the Extraction Merger closing date.

Further, Civitas executed warrant agreements to replace the warrants previously issued by Extraction consisting of (i) 3.4 million Tranche A warrants to purchase Civitas Common Stock at an exercise price of $91.91 in whole or in part, at any time or from time to time on or before January 20, 2025, issued pursuant to a warrant agreement by and between Civitas and Broadridge Corporate Issuer Solutions, Inc., as warrant agent (“Broadridge”), dated as of November 1, 2021 (the “Tranche A Warrants”), and (ii) 1.7 million Tranche B warrants to purchase Civitas Common Stock at an exercise price of $104.45 in whole or in part, at any time or from time to time on or before (i) January 20, 2026, issued pursuant to a warrant agreement by and between Civitas and Broadridge, as warrant agent, dated as of November 1, 2021 (the “Tranche B Warrants,” and, together with the Tranche A Warrants, the “Warrants”). A holder of a warrant, in its capacity as such, is not entitled to any rights whatsoever as a stockholder of Civitas, except to the extent expressly provided in the applicable warrant agreement. Please refer to *Note 8 - Fair Value Measurements* for further discussion.

The purchase price allocation was finalized as of the fourth quarter of 2022. The following tables present the merger consideration and final purchase price allocation of the assets acquired and the liabilities assumed in the Extraction Merger:

Merger Consideration (in thousands, except per share amount)		
Shares of Civitas Common Stock issued as merger consideration [(1)]		31,095
Closing price per share of Civitas Common Stock [(2)]	$	56.10
Merger consideration paid in shares of Civitas Common Stock	$	1,744,431
Unvested restricted stock compensation expense allocated as merger consideration	$	19,338
Unvested performance restricted stock compensation expense allocated as merger consideration		2,897
Total stock compensation expense allocated as merger consideration	$	22,235
Tranche A warrants issued as merger consideration	$	52,164
Tranche B warrants issued as merger consideration		25,299
Total warrants issued as merger consideration	$	77,463
Total merger consideration	$	1,844,129

(1) Based on the number of shares of common stock of Extraction issued and outstanding as of November 1, 2021 and the conversion ratio of 1.1711 per share of Civitas Common Stock.

(2) Based on the closing stock price of Civitas Common Stock on November 1, 2021.

Purchase Price Allocation (in thousands)		
Assets Acquired		
Cash and cash equivalents	$	106,360
Accounts receivable - oil, natural gas, and NGL sales		119,585
Accounts receivable - joint interest and other		33,054
Prepaid expenses and other		3,044
Inventory of oilfield equipment		9,291
Derivative assets		5,834
Proved properties		1,878,887
Unproved properties		193,400
Other property and equipment		40,068
Right-of-use assets		6,883
Deferred income tax assets		49,194
Other noncurrent assets		4,248
Total assets acquired	$	2,449,848
Liabilities Assumed		
Accounts payable and accrued expenses	$	90,353
Production taxes payable		63,572
Oil and natural gas revenue distribution payable		183,875
Income tax payable		14,000
Lease liability		6,883
Derivative liability		100,474
Ad valorem taxes		76,071
Asset retirement obligations		68,741
Other noncurrent liabilities		1,750
Total liabilities assumed		605,719
Net assets acquired	$	1,844,129

The valuation of oil and natural gas properties for the Extraction Merger applied a market-based weighted-average cost of capital rate of approximately 10%.

Crestone Peak Merger

On November 1, 2021, Civitas completed its merger with CPPIB Crestone Peak Resources America Inc. (“Crestone Peak”), pursuant to the terms of the related Agreement and Plan of Merger (the “Crestone Merger Agreement”) (the “Crestone Peak Merger”). Pursuant to the Crestone Merger Agreement, the shares of Crestone Peak common stock were converted into 22.5 million shares of Civitas Common Stock.

The purchase price allocation was finalized as of the fourth quarter of 2022. The following tables present the merger consideration and final purchase price allocation of the assets acquired and the liabilities assumed in the Crestone Peak Merger:

Merger Consideration (in thousands, except per share amount)		
Shares of Civitas Common Stock issued as merger consideration		22,500
Closing price per share of Civitas Common Stock [(1)]	$	56.10
Merger consideration paid in shares of Civitas Common Stock	$	1,262,250

(1) Based on the closing stock price of Civitas Common Stock on November 1, 2021.

Purchase Price Allocation (in thousands)		
Assets Acquired		
Cash and cash equivalents	$	67,505
Accounts receivable - oil, natural gas, and NGL sales		81,340
Accounts receivable - joint interest and other		9,917
Prepaid expenses and other		2,929
Inventory of oilfield equipment		11,951
Proved properties		1,797,814
Unproved properties		453,321
Other property and equipment		7,980
Right-of-use assets		7,934
Total assets acquired	$	2,440,691
Liabilities Assumed		
Accounts payable and accrued expenses	$	134,791
Production taxes payable		52,435
Oil and natural gas revenue distribution payable		83,950
Lease liability		7,934
Derivative liability		338,383
Credit facility		280,000
Ad valorem taxes		66,913
Deferred income tax liabilities		125,086
Asset retirement obligations		88,949
Total liabilities assumed		1,178,441
Net assets acquired	$	1,262,250

The valuation of oil and natural gas properties for the Crestone Peak Merger applied a market-based weighted-average cost of capital rate of approximately 10%.

Revenue and earnings of the acquiree

The amount of revenue of HighPoint, Extraction, and Crestone Peak included in our statement of operations during the year ended December 31, 2021 was approximately $244.7 million, $172.3 million, and $114.8 million, respectively. We determined that disclosing the amount of HighPoint, Extraction, and Crestone Peak related earnings included in the statements of operation is impracticable, as the operations from these mergers were integrated into the operations of the Company from the dates of each acquisition.

Supplemental pro forma financial information

The following unaudited pro forma financial information (in thousands, except per share amounts) represents a summary of the consolidated results of operations for the year ended December 31, 2021 and 2020, assuming the HighPoint, Extraction, and Crestone Peak mergers had been completed as of January 1, 2020. The pro forma financial information is not necessarily indicative of the results of operations that would have been achieved if the mergers had been effective as of this date, or of future results, and includes certain non-recurring pro forma adjustments that were directly attributable to the business combinations (in thousands, except per share amounts).

	Year Ended December 31, 2021				
	As reported	HighPoint[1]	Extraction[2]	Crestone Peak[2]	Civitas Pro Forma Combined
Total revenue	$ 930,614	$ 72,019	$ 882,255	$ 508,038	$ 2,392,926
Net income (loss)	178,921	(46,434)	1,140,653	(227,083)	1,046,057
Net income per common share - basic	$ 4.82				$ 12.61
Net income per common share - diluted	$ 4.74				$ 12.52

(1) Based on a closing date of April 1, 2021.

(2) Based on a closing date of November 1, 2021.

	Year Ended December 31, 2020				
	As reported	HighPoint	Extraction	Crestone Peak	Civitas Pro Forma Combined
Total revenue	$ 218,090	$ 250,347	$ 557,904	$ 285,426	$ 1,311,767
Net income (loss)	103,528	(1,081,347)	(1,335,406)	(268,057)	(2,581,282)
Net income (loss) per common share - basic	$ 4.98				$ (28.83)
Net income (loss) per common share - diluted	$ 4.95				$ (28.83)

Bison Acquisition

On March 1, 2022, the Company acquired the privately held DJ Basin operator Bison Oil & Gas II, LLC ("Bison") for merger consideration of approximately $280.4 million (the "Bison Acquisition"). Net assets acquired under the purchase price allocation were $294.0 million and consequently resulted in a bargain purchase gain of $13.6 million. Because of the immateriality of the Bison Acquisition, the related revenue and earnings, supplemental pro forma financial information, and detailed purchase price allocation are not disclosed.

Merger transaction costs

Merger transaction costs related to the aforementioned mergers and acquisitions are accounted for separately from the assets acquired and liabilities assumed and are included in merger transaction costs in the statements of operations. The Company incurred merger transaction costs of $24.7 million, $43.6 million, and $6.7 million during the years ended December 31, 2022, 2021, and 2020, respectively.

Acquisition of additional working interests in Company-operated wells

On July 5, 2022, the Company acquired additional working interests in certain Company-operated wells for cash consideration of $80.7 million, after customary purchase price adjustments.

NOTE 3 - REVENUE RECOGNITION

Oil and natural gas sales revenue presented within the accompanying statements of operations is reflective of the revenue generated from contracts with customers. Revenue attributable to each identified revenue stream is disaggregated below (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Operating net revenues:			
Oil sales	$ 2,536,134	$ 614,811	$ 174,536
Natural gas sales	695,079	144,708	24,243
NGL sales	560,185	171,095	19,311
Oil and natural gas sales	$ 3,791,398	$ 930,614	$ 218,090

For the years ended December 31, 2022, 2021, and 2020 revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was insignificant. As of December 31, 2022 and 2021, the Company's receivables from contracts with customers were $343.5 million and $362.3 million, respectively.

NOTE 4 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

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

	As of December 31,	
	2022	2021
Accounts payable trade	$ 31,783	$ 19,623
Accrued drilling and completion costs	137,171	129,430
Accrued lease operating expense and gathering, transportation, and processing	77,507	19,077
Accrued general and administrative expense	20,054	21,163
Accrued merger transaction costs	—	1,475
Accrued commodity derivative settlements	12,514	26,601
Accrued interest expense	5,509	6,303
Accrued settlement	1,497	20,791
Other accrued expenses	9,262	1,725
Total accounts payable and accrued expenses	$ 295,297	$ 246,188

NOTE 5 - LONG-TERM DEBT

5.0% Senior Notes

On October 13, 2021, the Company issued $400.0 million aggregate principal amount of 5.0% Senior Notes due 2026 (the "5.0% Senior Notes") pursuant to an indenture (the "5.0% Indenture"), among Civitas Resources, Wells Fargo Bank, National Association, as trustee, and the guarantors party thereto. The Company used the net proceeds and cash on hand to repay all borrowings under the Credit Facility (as defined below), all borrowings outstanding under the Crestone Peak credit facility, and for general corporate purposes. Interest accrues at the rate of 5.0% per annum and is payable semiannually in arrears on April 15 and October 15 of each year. Payments commenced on April 15, 2022.

The 5.0% Indenture contains covenants that limit, among other things, the Company's ability to: (i) incur or guarantee additional indebtedness; (ii) create liens securing indebtedness; (iii) pay dividends on or redeem or repurchase stock or subordinated debt; (iv) make specified types of investments and acquisitions; (v) enter into or permit to exist contractual limits on the ability of the Company's subsidiaries to pay dividends to Civitas Resources; (vi) enter into transactions with affiliates; and (vii) sell assets or merge with other companies. These covenants are subject to a number of important limitations and exceptions. The Company was in compliance with all covenants under the 5.0% Indenture as of December 31, 2022, and through the filing of this report. In addition, certain of these covenants will be terminated before the 5.0% Senior Notes mature if at any time no default or event of default exists under the 5.0% Indenture and the 5.0% Senior Notes receive an investment-grade rating from at least two ratings agencies. The 5.0% Indenture also contains customary events of default.

At any time prior to October 15, 2023, the Company may redeem the 5.0% Senior Notes, in whole or in part, at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) the "make-whole" premium at the redemption date, plus (iii) accrued and unpaid interest, if any. On or after October 15, 2023, the Company may redeem all or part of the 5.0% Senior Notes at redemption prices (expressed as percentages of the principal amount redeemed) equal to (i) 102.5% for the twelve-month period beginning on October 15, 2023; (ii) 101.25% for the twelve-month period beginning on October 15, 2024; and (iii) 100.0% for the twelve-month period beginning October 15, 2025 and at any time thereafter, plus accrued and unpaid interest, if any.

The Company may redeem up to 35% of the aggregate principal amount of the 5.0% Senior Notes at any time prior to October 15, 2023 with an amount not to exceed the net cash proceeds from certain equity offerings at a redemption price equal to 105.0% of the principal amount of the 5.0% Senior Notes redeemed, plus accrued and unpaid interest, if any, provided, however, that (i) at least 65.0% of the aggregate principal amount of the 5.0% Senior Notes originally issued on the issue date (but excluding 5.0% Senior Notes held by the Company) remains outstanding immediately after the occurrence of such redemption (unless all such 5.0% Senior Notes are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days after the date of the closing of such equity offering.

The 5.0% Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of Civitas' existing subsidiaries.

7.5% Senior Notes

In conjunction with the HighPoint Merger, the Company issued $100.0 million aggregate principal amount of 7.5% Senior Notes due 2026 (the "7.5% Senior Notes") pursuant to an indenture, dated April 1, 2021, by and among Civitas Resources, U.S. Bank National Association, as trustee, and the guarantors party thereto. Interest accrued at the rate of 7.5% per annum and was payable semiannually in arrears on April 30 and October 31 of each year. On May 1, 2022, the Company redeemed all of the issued and outstanding 7.5% Senior Notes at 100.0% of their aggregate principal amount, plus accrued and unpaid interest thereon to the redemption date.

The 7.5% Senior Notes and 5.0% Senior Notes are recorded net of unamortized deferred financing costs within senior notes on the accompanying balance sheets. There were no discounts or premiums associated with either issuance. The tables below present the related carrying values as of December 31, 2022 and December 31, 2021 (in thousands):

	As of December 31, 2022		
	Principal Amount	Unamortized Deferred Financing Costs	Net Amount
5.0% Senior Notes	$ 400,000	$ 6,707	$ 393,293

	As of December 31, 2021		
	Principal Amount	Unamortized Deferred Financing Costs	Net Amount
7.5% Senior Notes	$ 100,000	$ —	$ 100,000
5.0% Senior Notes	$ 400,000	$ 8,290	$ 391,710

Credit Facility

The Company is party to a reserve-based revolving facility, as the borrower, with JPMorgan Chase Bank, N.A. ("JPMorgan"), as the administrative agent, and a syndicate of financial institutions (the "Lender Syndicate"), as lenders, that has an aggregate maximum commitment amount of $2.0 billion and matures on November 1, 2025 (with all subsequent amendments, the "Credit Facility" or the "Credit Agreement").

The Credit Facility is guaranteed by all restricted domestic subsidiaries of the Company, and is secured by first priority security interests on substantially all assets, including a mortgage on at least 90% of the total value of the proved properties evaluated in the most recently delivered reserve reports prior to the amendment effective date, including any engineering reports relating to the oil and natural gas properties of the restricted domestic subsidiaries of the Company, subject to customary exceptions.

The Credit Facility contains customary representations and affirmative covenants. The Credit Facility also contains customary negative covenants, which, among other things, and subject to certain exceptions, include restrictions on (i) liens, (ii) indebtedness, guarantees and other obligations, (iii) restrictions in agreements on liens and distributions, (iv) mergers or consolidations, (v) asset sales, (vi) restricted payments, (vii) investments, (viii) affiliate transactions, (ix) change of business, (x) foreign operations or subsidiaries, (xi) name changes, (xii) use of proceeds, letters of credit, (xiii) gas imbalances, (xiv) hedging transactions, (xv) additional subsidiaries, (xvi) changes in fiscal year or fiscal quarter, (xvii) operating leases, (xviii) prepayments of certain debt and other obligations, (xix) sales or discounts of receivables, (xx) dividend payment thresholds, and (xxi) cash balances.

In addition, the Company is subject to certain financial covenants under the Credit Facility, as tested on the last day of each fiscal quarter, including, without limitation, (a) permitted net leverage ratio of 3.00 to 1 and (b) a current ratio, inclusive of the unused commitments then available to be borrowed, to not be less than 1.00 to 1. The Company was in compliance with all covenants under the Credit Facility as of December 31, 2022, and through the filing of this report.

On April 20, 2022, the Company entered into an amendment to the Credit Agreement that increased the Company's borrowing base from $1.0 billion to $1.7 billion and increased the aggregate elected commitments from $800.0 million to $1.0 billion.

In addition, this amendment resulted in the removal and replacement of LIBOR with the Secured Overnight Financing Rate ("SOFR") as a mechanism to determine interest for borrowings made under the Credit Facility using a term-specific SOFR. As a result, borrowings under the Credit Facility bear interest at a per annum rate equal to, at the option of the Company, either (i) the Alternate Base Rate ("ABR", for ABR Revolving Credit Loans) plus the applicable margin, or (ii) the term-specific SOFR plus the applicable margin. ABR is established as a rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan as its prime rate, (b) the applicable rate of interest published by the Federal Reserve Bank of New York plus 0.5%, or (c) the term-specific SOFR plus 1.0%, subject to a 1.5% floor plus the applicable margin of 1.0% to 2.0%, based on the utilization of the Credit Facility. Term-specific SOFR is based on one-, three-, or six-month terms as selected by the Company and is subject to a 0.5% floor plus the applicable margin of 2.0% to 3.0%, based on the utilization of the Credit Facility. Interest on borrowings that bear interest at the SOFR shall be payable on the last day of the applicable interest period selected by the Company, and interest on borrowings that bear interest at the ABR shall be payable quarterly in arrears.

On October 27, 2022, and as part of the regularly scheduled, semi-annual borrowing base redetermination under the Credit Facility, the Company's aggregate elected commitments of $1.0 billion were reaffirmed and borrowing base was increased from $1.7 billion to $1.85 billion. The next scheduled borrowing base redetermination date is set to occur in April 2023.

The following table presents the outstanding balance, total amount of letters of credit outstanding, and available borrowing capacity under the Credit Facility as of the dates indicated (in thousands):

	February 22, 2023	December 31, 2022	December 31, 2021
Revolving credit facility	$ —	$ —	$ —
Letters of credit	12,100	12,100	21,656
Available borrowing capacity	987,900	987,900	778,344
Total aggregate elected commitments	$ 1,000,000	$ 1,000,000	$ 800,000

In connection with the amendments to the Credit Facility, the Company capitalized a total of approximately $11.9 million in deferred financing costs. Of the total post-amortization net capitalized amounts, (i) $5.5 million and $7.5 million are presented within other noncurrent assets on the accompanying balance sheets as of December 31, 2022 and 2021, respectively, and (ii) $3.0 million and $2.7 million are presented within prepaid expenses and other on the accompanying balance sheets as of December 31, 2022 and 2021, respectively.

Interest Expense

For the years ended December 31, 2022, 2021, and 2020, the Company incurred interest expense of $32.2 million, $16.0 million, and $3.8 million respectively. The Company capitalized zero, $6.3 million, and $1.8 million of interest expense during the years ended December 31, 2022, 2021, and 2020, respectively.

NOTE 6 - COMMITMENTS AND CONTINGENCIES

Legal Proceedings

From time to time, the Company is involved in various commercial and regulatory claims, litigation, and other legal proceedings that arise in the ordinary course of its business. The Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. In accordance with authoritative accounting guidance, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the most likely anticipated outcome or the minimum amount within a range of possible outcomes. Because legal proceedings are inherently unpredictable and unfavorable resolutions could occur, assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies, the Company may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, and/or the ongoing discovery and development of information important to the matters. The Company regularly reviews contingencies to determine the adequacy of its accruals and related disclosures.

Upon closing of the HighPoint, Extraction, and Crestone Peak mergers and Bison Acquisition, the Company assumed all obligations, whether asserted or unasserted, of HighPoint, Extraction, Crestone Peak, and Bison. As of the filing date of this report, there were no probable, material pending, or overtly threatened legal actions against the Company of which it was aware, other than the following:

Boulder County. In prior periods, there was ongoing litigation between Boulder County and Extraction which has been previously disclosed as having the potential to prevent oil and gas operations for the development of minerals contained within Boulder County, Colorado. Boulder County had initiated suit in District Court for Boulder County that was primarily a contract case, where the relevant contracts were the conservation easement over the Blue Paintbrush location, Extraction's Surface Use Agreement for the Blue Paintbrush location, and the leases that Boulder owns within the Blue Paintbrush drilling and spacing unit. Boulder sought invalidation of these leases in the litigation. This litigation has been resolved as to all substantive issues, and the Company is awaiting final dismissal of the matter by the trial court.

In May 2022, the Company became aware that Boulder County is alleging new legal theories and requesting termination of the leases previously at issue in the Blue Paintbrush litigation. No formal action has been initiated, but the Company intends to vigorously defend against all claims alleged by Boulder County. If an action is brought by Boulder County, an adverse outcome in any such litigation could result in the Company failing to meet its development objectives in Blue Paintbrush.

Enforcement. Disclosure of certain environmental matters is required when a governmental authority is a party to the proceedings and the proceedings involve potential monetary sanctions that the Company believes could exceed $0.3 million. The Company has received Notices of Alleged Violations ("NOAV") from the COGCC alleging violations of various Colorado statutes and COGCC regulations governing oil and gas operations. The Company has further received notices from the Colorado Air Pollution Control Division. The Company continues to engage in discussions regarding resolution of the alleged violations. As of December 31, 2022 and December 31, 2021, the Company accrued approximately $0.7 million and $1.0 million, respectively, associated with the NOAVs and Colorado Air Pollution Control Division notices, as they were probable and reasonably estimable.

Commitments

Firm Transportation Agreements. The Company is party to a firm pipeline transportation contract to provide a guaranteed outlet for production on an oil pipeline system. The contract requires the Company to pay minimum volume transportation charges on 12,500 barrels per day through April 2025, regardless of the amount of pipeline capacity utilized by the Company. The aggregate financial commitment fee over the remaining term was $34.0 million as of December 31, 2022. The Company expects to utilize most, if not all, of the firm capacity on the oil pipeline system.

Minimum Volume Agreement - Oil. The Company is party to a purchase agreement to deliver fixed and determinable quantities of crude oil. Under the terms of the agreement, the Company is required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitment of 20,000 gross Bbls per day over a term ending in December 2023. The aggregate financial commitment fee over the remaining term is $47.3 million as of December 31, 2022. The Company has not and does not expect to incur any deficiency payments.

Minimum Volume Agreement - Gas and Other. The Company is party to a gas gathering and processing agreement (the "Gathering Agreement") with a third-party midstream provider over a term ending in 2029 with an annual minimum volume commitment of 13.0 billion cubic feet of natural gas. The Gathering Agreement also includes a commitment to sell take-in-kind NGLs from other processing agreements of 7,500 Bbls a day through 2026 with the ability to roll forward up to a 10% shortfall in a given month to the subsequent month. The aggregate financial commitment over the remaining term is $121.7 million as of December 31, 2022, which fluctuates with commodity prices as this is a value-based percentage of proceeds sales contract. Based on current projections, the Company may incur approximately $52.6 million of shortfall payments under the Gathering Agreement during the remaining term of approximately seven years; however, the Company is actively engaging alternative strategies to reduce any potential contract deficiencies incurred in future periods.

Additionally, the Company is also party to a gas gathering and processing agreement with several third-party producers and a third-party midstream provider to deliver to two different plants over terms that end in August 2025 and July 2026. The Company's share of these commitments requires an incremental 51.5 and 20.6 MMcf per day, respectively, over a baseline volume of 65 MMcf per day for a period of seven years following the in-service dates of the plants. The Company may be required to pay a shortfall fee for any incremental volume deficiencies under these commitments. These contractual obligations can be reduced by the Company's proportionate share of the collective volumes delivered to the plants by other incremental third-party volumes available to the midstream provider that are in excess of the total commitments. Because of the third-party producer reduction provision, we believe that the aggregate financial commitment fee over the remaining term is zero as of December 31, 2022. The Company has not and does not expect to incur any deficiency payments.

The Company is also party to additional individually immaterial agreements that require the Company to pay a fee associated with the minimum volumes over various terms ending in April 2025, regardless of the amount delivered. The aggregate financial commitment fee over the remaining term for these contracts was $8.3 million as of December 31, 2022.

The minimum annual payments under the these agreements for the next five years as of December 31, 2022 are presented below (in thousands):

	Firm Transportation	Minimum Volume[(1)]
2023	$ 14,600	$ 68,265
2024	14,640	20,604
2025	4,800	18,840
2026	—	17,728
2027 and thereafter	—	51,870
Total	$ 34,040	$ 177,307

(1) The above calculation is based on the minimum volume commitment schedule (as defined in the relevant agreement) and applicable differential fees.

Other commitments. The Company is party to a drilling commitment agreement with a third-party midstream provider such that the Company is required to drill and complete a total of 106 qualifying wells, whereby a minimum number of wells out of the total must be drilled by a deadline occurring every two years over a period ending December 31, 2026. The drilling commitment agreement provides for, among other things, a number of specifications such as minimum consecutive days of production, well performance, and lateral length. Wells operated by others can satisfy this commitment, subject to limitations. If the Company were to fail to complete the wells by the applicable deadline, it would be in breach of the agreement and the third-party midstream provider could attempt to assert damages against Civitas and its affiliates. As of the date of filing, the Company cannot reasonably estimate how much, if any, damages will be paid.

Refer to *Note 13 - Leases* for lease commitments.

NOTE 7 - STOCK-BASED COMPENSATION

Long Term Incentive Plans

In April 2017, the Company adopted the 2017 Long Term Incentive Plan ("2017 LTIP"), which provides for the issuance of restricted stock units, performance stock units, and stock options, and reserved 2,467,430 shares of common stock. In June 2021, the Company adopted the 2021 Long Term Incentive Plan ("2021 LTIP"), which reserved an incremental 700,000 shares of common stock to those previously reserved under the 2017 LTIP. Finally, pursuant to the Extraction Merger Agreement, Civitas assumed the Extraction Equity Plan, which reserved 3,305,080 shares of common stock now issuable by Civitas. The 2017 LTIP, 2021 LTIP, and Extraction Equity Plan are collectively referred to herein as the "LTIP".

In November 2021, the Company adopted a non-employee director compensation program (the "Director Compensation Program"), which provides that non-employee directors will receive grants of deferred stock units ("DSUs"). In connection with the adoption of the Director Compensation Program, the Company adopted a First Amendment to the 2021 LTIP that, among other things, allows the Company to determine whether dividend rights granted pursuant to the LTIP should be reinvested, paid currently or paid in accordance with the terms of an associated award.

The Company records compensation expense associated with the issuance of awards under the LTIP on a straight-line basis over the vesting period based on the fair value of the awards as of the date of grant within general and administrative expense. The following table outlines the compensation expense recorded by type of award (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Restricted and deferred stock units	$ 19,401	$ 11,895	$ 5,283
Performance stock units	11,966	3,663	748
Stock options	—	—	125
Total stock-based compensation	$ 31,367	$ 15,558	$ 6,156

As of December 31, 2022, unrecognized compensation expense related to the awards granted under the LTIP will be amortized through the relevant periods as follows (in thousands):

	Unrecognized Compensation Expense	Final Year of Recognition
Restricted and deferred stock units	$ 16,801	2025
Performance stock units	15,340	2024
Total unrecognized stock-based compensation	$ 32,141	

Restricted Stock Units ("RSUs") and Deferred Stock Units

The Company typically grants RSUs to officers, directors, and employees and DSUs to directors as part of its LTIP. Each RSU and DSU represents a right to receive one share of the Company's common stock upon settlement of the award at the end of the specified vesting period.

RSUs generally vest and settle either over a (i) one-year vesting period, with the entire grant vesting and settling on the anniversary date or (ii) three-year vesting period, with one-third of the total grant vesting and settling on each anniversary date. DSUs generally vest in quarterly installments over a one-year period following the grant date. DSUs are settled in shares of the Company's common stock upon the director's separation of service from the Board. The fair value of RSUs and DSUs is equal to the closing price of the Company's common stock on the date of the grant.

A summary of the status and activity of non-vested RSUs and DSUs for the year ended December 31, 2022 is presented below:

	RSUs and DSUs	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	815,062	$ 42.18
Granted	573,524	51.34
Vested	(647,178)	42.07
Forfeited	(65,510)	39.96
Non-vested, end of year	675,898	$ 50.27

The fair value of the RSUs and DSUs granted under the LTIP during the year ended December 31, 2022 was $29.4 million.

Performance Stock Units ("PSUs")

The Company grants PSUs to officers as part of its LTIP. The number of shares of the Company's common stock issued to settle PSUs ranges from zero to two times the number of PSUs granted and is determined based on performance achievement against certain criteria over a three-year performance period. PSUs generally vest and settle on the third anniversary of the date of the grant.

Performance achievement is determined based on one to two criteria. The first criterion is based on either, or a combination of, the Company's absolute and relative total shareholder return ("TSR") over the performance period. Absolute TSR is determined based upon the performance of the Company's common stock over the performance period relative to the price of the Company's common stock at the grant date. For awards with relative TSR component, the Company's absolute TSR is compared with the absolute TSRs of a group of peer companies over the performance period. The absolute TSR for the Company and each of the peer companies is determined by dividing (A) (i) the volume-weighted average share price for the last 30 trading days of the performance period, minus (ii) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period, plus (iii) dividends paid by (B) the volume-weighted average share price for the 30 trading days preceding the beginning of the performance period. The resultant amount is then annualized based on the length of the performance period. The second criterion, if applicable, is based on the Company's annual return on average capital employed ("ROCE") for each year during the three-year performance period.

The total number of PSUs granted under the LTIP was split as follows for the relevant grant years:

	2022	2021	2020
TSR	100 %	100 %	67 %
ROCE	— %	— %	33 %

The compensation expense associated with PSUs that are dependent on a performance-based settlement criterion is adjusted based on the number of units expected to vest based on the Company's expected ROCE performance.

Of the grant-date fair value, the portion of the PSUs tied to TSR performance required a stochastic process method using a Brownian Motion simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the PSUs tied to TSR performance, the Company could not predict with certainty the path its stock price or the stock prices of its peers would take over the performance period. By using a stochastic simulation, the Company created multiple prospective stock pathways, statistically analyzed these simulations, and ultimately made inferences regarding the most likely path the stock price would take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Brownian Motion Model, was deemed an appropriate method by which to determine the fair value of the portion of the PSUs tied to TSR performance. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the performance period, as well as the volatilities for each of the Company's peers.

The following table presents the range of assumptions used to determine the fair value of the PSUs with market-based settlement criteria as granted under the LTIP throughout each of the periods presented:

	Year Ended December 31,		
	2022	2021	2020
Expected term (in years)	3.2	2.2 to 3.0	3.0
Risk-free interest rate	1.8% to 3.2%	0.3% to 0.6%	0.2%
Expected daily volatility	4.0% to 4.7%	3.8% to 4.7%	3.5%

A summary of the status and activity of non-vested PSUs for the year ended December 31, 2022 is presented below:

	PSUs [(1)]	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	319,367	$ 57.58
Granted	282,224	65.65
Vested	(164,745)	41.03
Forfeited	(48,892)	49.39
Expired	(41,955)	22.77
Non-vested, end of year	345,999	$ 77.42

(1) The number of awards assumes that the associated performance condition is met at the target amount (multiplier of one). The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to two, depending on the level of satisfaction of the performance condition.

The fair value of the PSUs granted under the LTIP during the year ended December 31, 2022 was $18.5 million. The PSUs granted in 2020 vested as of December 31, 2022 and are expected to be released during the first quarter of 2023 with 200% and 92% of shares tied to TSR and ROCE performance, respectively, distributed to the recipients. In addition, certain PSUs vested during 2022 pursuant to change in control provisions in the applicable award agreements.

Stock Options

The LTIP allows for the issuance of stock options to the Company's employees at the sole discretion of the Board. Options expire ten years from the grant date unless otherwise determined by the Board.

Stock options are valued using a Black-Scholes Model where expected volatility is based on an average historical volatility of a peer group selected by management over a period consistent with the expected life assumption on the grant date, the risk-free rate of return is based on the U.S. Treasury constant maturity yield on the grant date with a remaining term equal to the expected term of the awards, and the Company's expected life of stock option awards is derived from the midpoint of the average vesting time and contractual term of the awards.

A summary of the status and activity of non-vested stock options for the year ended December 31, 2022 is presented below:

	Stock Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding, beginning of year	25,549	$ 34.36		
Exercised	(9,161)	34.36		
Forfeited	(1,218)	34.36		
Outstanding, end of year	15,170	$ 34.36	1.3	$ 358
Options outstanding and exercisable	15,170	$ 34.36	1.3	$ 358

The aggregate intrinsic value of options exercised during the year ended December 31, 2022 was $0.2 million.

NOTE 8 - FAIR VALUE MEASUREMENTS

The Company follows authoritative accounting guidance for measuring the fair value of assets and liabilities in its financial statements. This guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Further, this guidance establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available.

The fair value hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices in active markets for identical assets or liabilities

Level 2: Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable

Level 3: Significant inputs to the valuation model are unobservable

Financial and non-financial assets and liabilities 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 and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil and natural gas commodity price derivatives. The fair value of the Company's commodity price derivatives is estimated using industry-standard models that contemplate various inputs including, but not limited to, the contractual price of the underlying position, current market prices, forward commodity price curves, volatility factors, time value of money, and the credit risk of both the Company and its counterparties. We validate our fair value estimate by corroborating the original source of inputs, monitoring changes in valuation methods and assumptions, and reviewing counterparty mark-to-market statements and other supporting documentation. Refer to *Note 9 - Derivatives* for more information regarding the Company's derivative instruments.

The following tables present the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2022 and 2021 and their classification within the fair value hierarchy (in thousands):

	As of December 31, 2022		
	Level 1	Level 2	Level 3
Derivative assets	$ —	$ 3,284	$ —
Derivative liabilities	$ —	$ 63,533	$ —

	As of December 31, 2021		
	Level 1	Level 2	Level 3
Derivative assets	$ —	$ 3,393	$ —
Derivative liabilities	$ —	$ 239,763	$ —

Long-Term Debt

The 5.0% Senior Notes are recorded at cost, net of any unamortized deferred financing costs. As of December 31, 2022, the fair value of the 5.0% Senior Notes was $369.4 million. This fair value is based on quoted market prices, and as such, is designated as Level 1 within the fair value hierarchy. The recorded value of the Credit Facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. Please refer to *Note 5 - Long-Term Debt* for additional information.

Warrants

As discussed in *Note 2 - Acquisitions and Divestitures*, the Company issued warrants in connection with the Extraction Merger. The warrants issued are indexed to the Company's common stock and are required to be net share settled via a cashless exercise. The Company evaluated the warrants under authoritative accounting guidance and determined that they should be classified as equity instruments. The Company's share price traded below the exercise price of the warrants and therefore were not exercisable during the years ended December 31, 2022 and 2021.

The fair value of the warrants on the issuance date was determined using Level 3 inputs including, but not limited to, volatility, risk-free rate, and dividend yield under the Cox-Ross-Rubinstein binomial option pricing model. The warrants were included as a component of merger consideration and are recorded within additional paid-in capital on the accompanying balance sheets at a fair value of $77.5 million, with no recurring fair value measurement required. There have been no changes to the initial carrying amount of the warrants since issuance.

Acquisitions and Impairments of Proved and Unproved Properties

We measure acquired assets or businesses at fair value on a nonrecurring basis and review our proved and unproved oil and natural gas properties for impairment using inputs that are not observable in the market, and are therefore designated as Level 3 within the valuation hierarchy. During the years ended December 31, 2022, 2021, and 2020, the Company recorded no impairments of proved properties and incurred $18.0 million, $57.3 million, and $37.3 million, respectively, of abandonment and impairment of unproved properties. Please refer to *Note 1 – Summary of Significant Accounting Policies* for information on the Company's policies for determining fair value of its proved and unproved properties and related impairment expense.

NOTE 9 - DERIVATIVES

The Company periodically enters into commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices for its expected future oil and natural gas production and the associated impact on cash flows. The Company's commodity derivative contracts consist of swaps, collars, and basis protection swap arrangements. As of December 31, 2022, all derivative counterparties were members of the Credit Facility lender group and all commodity derivative contracts are entered into for other-than-trading purposes. The Company does not designate its commodity derivative contracts as hedging instruments.

A typical swap arrangement guarantees a fixed price on contracted volumes. If the agreed upon published third-party index price ("index price") is lower than the fixed contract price at the time of settlement, the Company receives the difference between the index price and the fixed contract price. If the index price is higher than the fixed contact price at the time of settlement, the Company pays the difference between the index price and the fixed contract price.

A typical collar arrangement establishes a floor and ceiling price on contracted volumes through the use of a short call and a long put ("two-way collar"). When the index price is above the ceiling price at the time of settlement, the Company pays the difference between the index price and the ceiling price. When the index price is below the floor price at the time of settlement, the Company receives the difference between the index price and floor price. When the index price is between the floor price and ceiling price, no payment or receipt occurs. A minority of our collar arrangements combine a two-way collar with a short put that holds an exercise price below the floor price ("three-way collar"). In these arrangements, when the index price is below the floor price at the time of settlement, the Company receives the difference between the index price and the floor price, capped at the difference between the floor price and the exercise price of the short put.

Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For basis protection swaps, the Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

As of December 31, 2022, the Company had entered into the following commodity price derivative contracts:

	Contract Period				
	Q1 2023	Q2 2023	Q3 2023	Q4 2023	2024
Oil Derivatives (volumes in Bbl/day and prices in $/Bbls)					
Swaps					
NYMEX WTI Volumes	1,320	1,205	1,053	984	1,019
Weighted-Average Contract Price	$ 74.29	$ 73.49	$ 70.92	$ 70.61	$ 66.78
Two-Way Collars					
NYMEX WTI Volumes	1,054	—	—	—	—
Weighted-Average Ceiling Price	$ 72.70	$ —	$ —	$ —	$ —
Weighted-Average Floor Price	$ 40.00	$ —	$ —	$ —	$ —
Three-Way Collars					
NYMEX WTI Volumes	1,721	1,436	1,302	1,172	143
Weighted-Average Ceiling Price	$ 58.75	$ 57.69	$ 57.48	$ 56.49	$ 56.25
Weighted-Average Floor Price	$ 49.31	$ 48.10	$ 47.91	$ 49.04	$ 45.00
Weighted-Average Sold Put Price	$ 39.25	$ 37.70	$ 37.41	$ 39.04	$ 35.00
Natural Gas Derivatives (volumes in MMBtu/day and prices in $/MMBtu)					
Swaps					
NYMEX HH Volumes	47,368	46,374	46,120	45,947	24,148
Weighted-Average Contract Price	$ 2.65	$ 2.64	$ 2.61	$ 2.60	$ 2.70
Two-Way Collars					
NYMEX HH Volumes	9,558	1,563	1,887	1,756	1,033
Weighted-Average Ceiling Price	$ 3.23	$ 2.78	$ 2.96	$ 2.96	$ 3.05
Weighted-Average Floor Price	$ 2.03	$ 2.21	$ 2.34	$ 2.38	$ 2.38
Three-Way Collars					
NYMEX HH Volumes	899	505	—	—	303
Weighted-Average Ceiling Price	$ 3.19	$ 3.33	$ —	$ —	$ 3.49
Weighted-Average Floor Price	$ 2.50	$ 2.50	$ —	$ —	$ 2.50
Weighted-Average Sold Put Price	$ 2.00	$ 2.00	$ —	$ —	$ 2.00

Subsequent to December 31, 2022, the Company entered into a series of fixed price, natural gas basis protection swaps on all of its outstanding NYMEX HH positions through the third quarter of 2024 to mitigate exposure to adverse pricing differentials between NYMEX HH and CIG. The weighted-average contract price entered of $(0.13) per MMBtu represents the amount of reduction to the NYMEX HH natural gas price for the contracted volumes covered by the basis protection swaps.

Derivative Assets and Liabilities Fair Value

The Company's commodity price derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The following table contains a summary of all the Company's derivative positions reported on the accompanying balance sheets as well as a reconciliation between the gross assets and liabilities and the potential effects of master netting arrangements on the fair value of the Company's commodity derivative contracts as of December 31, 2022 and 2021 (in thousands):

	As of December 31,	
	2022	2021
Derivative Assets:		
Commodity contracts - current	$ 2,490	$ 3,393
Commodity contracts - noncurrent	794	—
Total derivative assets	3,284	3,393
Amounts not offset in the accompanying balance sheets	—	(3,393)
Total derivative assets, net	$ 3,284	$ —
Derivative Liabilities:		
Commodity contracts - current	$ (46,334)	$ (219,804)
Commodity contracts - long-term	(17,199)	(19,959)
Total derivative liabilities	(63,533)	(239,763)
Amounts not offset in the accompanying balance sheets	—	3,393
Total derivative liabilities, net	$ (63,533)	$ (236,370)

The following table summarizes the components of the derivative gain (loss) presented on the accompanying statements of operations for the periods below (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Derivative cash settlement gain (loss):			
Oil contracts	$ (346,419)	$ (215,057)	$ 50,133
Gas contracts	(189,410)	(51,806)	(727)
NGL contracts	(40,973)	(9,051)	—
Total derivative cash settlement gain (loss)	(576,802)	(275,914)	49,406
Change in fair value gain	241,642	215,404	4,056
Total derivative gain (loss)	$ (335,160)	$ (60,510)	$ 53,462

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties, including facilities requiring decommissioning. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is drilled or acquired, or a facility is constructed. The increase in carrying value is included in proved properties in the accompanying balance sheets. The Company depletes the amount added to proved properties and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective long-lived assets. Cash paid to settle asset retirement obligations is included in the cash flows from operating activities section of the accompanying statements of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience plugging and abandoning wells, estimated economic lives, estimated plugging and abandonment cost, and regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised.

A roll-forward of the Company's asset retirement obligation is as follows (in thousands):

	Year Ended December 31,	
	2022	2021
Balance, beginning of year	$ 225,315	$ 28,699
Additional liabilities incurred	3,031	183,758
Liabilities settled	(15,902)	(4,221)
Accretion expense	15,926	3,933
Revisions to estimate [1]	62,656	13,146
Balance, end of year	$ 291,026	$ 225,315
Current portion	25,557	24,000
Long-term portion	$ 265,469	$ 201,315

(1) Revisions to estimates for the year ended December 31, 2022 and 2021 were primarily a result of increases in the Company's estimated plugging and abandonment cost.

NOTE 11 - EARNINGS PER SHARE

Earnings per basic and diluted share are calculated under the treasury stock method. Basic net income per common share is calculated by dividing net income by the basic weighted-average common shares outstanding for the respective period. Diluted net income per common share is calculated by dividing net income by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of unvested RSUs, DSUs, PSUs as well as outstanding in-the-money stock options and warrants. When the Company recognizes a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of diluted earnings per share.

As discussed in *Note 7 - Stock-Based Compensation*, PSUs represent the right to receive a number of shares of the Company's common stock ranging from zero to two times the number of PSUs granted based on the performance achievement over the applicable performance period. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the performance period applicable to such awards.

The Company has also issued stock options and warrants, which both represent the right to purchase the Company's common stock at a specified exercise price. The number of potentially dilutive shares related to the stock options and warrants is based on the number of shares, if any, that would be exercisable at the end of the respective reporting period, assuming that date was the end of such stock options' or warrants' term. Stock options and warrants are only dilutive when the average price of the common stock during the period exceeds the exercise price.

The following table sets forth the calculations of basic and diluted net income per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2022	2021	2020
Net income	$ 1,248,080	$ 178,921	$ 103,528
Basic net income per common share	$ 14.68	$ 4.82	$ 4.98
Diluted net income per common share	$ 14.58	$ 4.74	$ 4.95
Weighted-average shares outstanding - basic	85,005	37,155	20,774
Add: dilutive effect of stock awards	599	591	138
Weighted-average shares outstanding - diluted	85,604	37,746	20,912

There were 20,699, 178,051, and 248,744 unvested awards that were anti-dilutive for the years ended December 31, 2022, 2021, and 2020 respectively. The exercise price of the Company's warrants was in excess of the Company's stock price during the years ended December 31, 2022 and 2021; therefore, they were excluded from the earnings per share calculation.

NOTE 12 - INCOME TAXES

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax basis of assets and liabilities and amounts reported in the accompanying balance sheets. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liabilities determines the periodic provision for deferred taxes.

The provision for income taxes consists of the following (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Current tax expense (benefit)			
Federal	$ 51,246	$ —	$ (27)
State	16,950	—	—
Total current tax expense (benefit)	68,196	—	(27)
Deferred tax expense (benefit)			
Federal	289,578	62,212	(53,784)
State	47,924	10,646	(6,736)
Total deferred tax expense (benefit)	337,502	72,858	(60,520)
Total income tax expense (benefit)	$ 405,698	$ 72,858	$ (60,547)

Temporary differences between the financial statement carrying amounts and tax basis of assets and liabilities that give rise to the net deferred tax liability and asset result from the following components (in thousands):

	As of December 31,	
	2022	2021
Deferred tax liabilities:		
Oil and gas properties	$ 868,612	$ 608,829
Right-of-use assets	5,915	8,292
Total deferred tax liabilities	874,527	617,121
Deferred tax assets:		
Federal and state tax net operating loss carryforward	432,096	482,216
Asset retirement obligations	71,092	51,515
Commodity derivative contracts	37,293	86,958
Inventory	13,783	10,108
Stock-based compensation	5,974	7,622
Lease liability	6,067	8,187
Property taxes	—	19,458
Transaction costs	1,461	—
Other long-term assets	12,547	21,474
Total deferred tax assets	580,313	687,538
Less: Valuation allowance	25,404	48,133
Total deferred tax assets after valuation allowance	554,909	639,405
Total non-current net deferred tax asset (liability)	$ (319,618)	$ 22,284

The following table outlines the Federal net operating loss ("NOL") carryforwards acquired and deferred tax assets and liabilities recorded as a result of the mergers that closed in 2021 (in millions):

	HighPoint Merger	Extraction Merger	Crestone Peak Merger
Federal NOL carryforwards [(1)]	$ 219.0	$ 479.9	$ 555.7
Deferred tax asset (liability)	$ 110.5	$ 49.2	$ (125.1)
Valuation allowance	(48.1)	—	—
Net deferred tax asset (liability)	$ 62.4	$ 49.2	$ (125.1)

(1) The net operating loss carryforwards acquired in the HighPoint, Extraction, and Crestone Peak mergers will be subject to an annual limitation under Section 382 of the Code of approximately $5.6 million, $7.0 million, and $16.8 million, respectively.

The Company had $1.8 billion and $2.0 billion of net operating loss carryovers for federal income tax purposes as of December 31, 2022 and 2021, respectively. Due to change of ownership provisions of Section 382 of the Code, utilization of net operating loss carryovers and other tax attributes are limited. Federal net operating loss carryforwards incurred prior to January 1, 2018 of $569.2 million will begin to expire in 2035. Federal net operating loss carryforwards incurred after December 31, 2017 of $1.2 billion have no expiration and can only be used to offset 80% of taxable income when utilized.

The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more-likely-than-not that all or a portion of the deferred tax assets will be realized. In making such determination, the Company considers all available (both positive and negative) evidence, including future reversals of temporary differences, tax-planning strategies, projected future taxable income, and results of operations. As a result of the HighPoint Merger, the Company had a valuation allowance of $25.4 million and $48.1 million as of December 31, 2022 and 2021, respectively, against certain acquired net operating losses and other tax attributes due to the limitation on realizability caused by the change of ownership provisions of Section 382 of the Code. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that the deferred tax assets will be realized.

Recorded income tax expense or benefit differs from the amount that would be provided by applying the statutory United States federal income tax rate of 21% to income before income taxes. These differences primarily relate to the effect of state income taxes, excess tax benefits and deficiencies on stock-based compensation awards, tax limitations on compensation of covered individuals, changes in valuation allowances, and other permanent differences, as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Federal statutory tax expense	$ 347,293	$ 52,824	$ 9,026
Increase (decrease) in tax resulting from:			
State tax expense, net of federal benefit	58,658	10,646	1,694
State tax rate change	—	—	124
Return to provision	19,975	27	292
Compensation of covered individuals	6,138	1,793	144
Stock-based compensation	(3,343)	(1,559)	690
Transaction costs	—	9,043	—
Bargain purchase gain	(2,852)	—	—
Tax credits	(1,405)	—	—
Change in valuation allowance	(19,302)	—	(72,553)
Other	536	84	36
Total income tax expense (benefit)	$ 405,698	$ 72,858	$ (60,547)

The Company had no unrecognized tax benefits as of December 31, 2022, 2021, and 2020. The tax returns for 2021, 2020, and 2019 are still subject to audit by the Internal Revenue Service.

On August 16, 2022, the Inflation Reduction Act ("IRA") was signed into law. Among other provisions, the IRA imposes a 15% corporate alternative minimum tax ("Corporate AMT") for tax years beginning after December 31, 2022, imposes a 1% excise tax on corporate stock repurchases after December 31, 2022, and provides tax incentives to promote various energy efficient initiatives. The Company is evaluating the potential impact of the Corporate AMT on our current income tax expense and income taxes payable; however, we currently do not believe this will materially affect our income taxes paid for the 2023 tax year.

NOTE 13 - LEASES

The Company's right-of-use assets and lease liabilities are recognized on the accompanying balance sheets based on the present value of the expected lease payments over the lease term. As of December 31, 2022 and 2021, the Company did not have any agreements in place that were classified as finance leases. The following table summarizes the asset classes of the Company's operating leases (in thousands):

	As of December 31,	
	2022	2021
Operating Leases		
Field equipment[1]	$ 15,131	$ 29,312
Corporate leases	8,235	9,484
Vehicles	759	1,089
Total right-of-use asset	$ 24,125	$ 39,885
Field equipment[1]	$ 15,131	$ 29,312
Corporate leases	8,898	9,870
Vehicles	759	1,089
Total lease liability	$ 24,788	$ 40,271

(1) Includes compressors, certain natural gas processing equipment, and other field equipment.

The following table summarizes the components of the Company's gross lease costs incurred for the periods below (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Operating lease cost[1]	$ 21,050	$ 15,449	$ 13,957
Short-term lease cost[2]	55,059	3,662	2,058
Sublease income[3]	(63)	(367)	(358)
Total lease cost[4]	$ 76,046	$ 18,744	$ 15,657

(1) Includes office rent expense of $4.3 million, $2.2 million, and $1.1 million for the years ended December 31, 2022, 2021, and 2020, respectively.
(2) Includes drilling rigs and other equipment. Short-term drilling rig costs include a non-lease labor component, which is treated as a single lease component.
(3) The Company subleased a portion of one of its office spaces for the remainder of the office lease term
(4) Variable lease costs represent differences between lease obligations and actual costs incurred for certain leases that do not have fixed payments related to both lease and non-lease components. Such incremental costs include lease payment increases or decreases driven by market price fluctuations and leased asset maintenance costs.Variable lease costs were not material for the years ended December 31, 2022, 2021, and 2020.

Lease costs disclosed above are presented on a gross basis. A portion of these costs may have been or will be billed to other working interest owners. The Company's net share of these costs is included in various line items on the accompanying statements of operations or capitalized to proved properties or other property and equipment, as applicable.

The Company recognizes operating lease cost on a straight-line basis. Short-term lease costs are recognized as incurred and represent payments for leases with a lease term of one year or less, excluding leases with a term of one month or less.

The Company's weighted-average remaining lease terms and discount rates as of December 31, 2022 are as follows:

	Operating Leases
Weighted-average lease term (years)	2.6
Weighted-average discount rate	4.0%

Future commitments by year for the Company's leases with a lease term of one year or more as of December 31, 2022 are presented in the table below. Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the accompanying balance sheets as follows (in thousands):

	Operating Leases
2023	$ 14,139
2024	5,737
2025	2,150
2026	1,803
2027	1,771
Thereafter	598
Total lease payments	26,198
Less: imputed interest	(1,410)
Total lease liability	$ 24,788

NOTE 14 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

Supplemental cash flow disclosures are presented below (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Supplemental cash flow information:			
Cash paid for income taxes	$ (97,800)	$ (14,000)	$ —
Cash paid for interest, net of capitalization	(28,528)	(1,829)	(1,546)
Supplemental non-cash investing and financing activities:			
Non-cash investing activities [(1)]	$ —	$ 4,911,186	$ —
Non-cash financing activities [(2)]	—	3,481,312	—
Changes in working capital related to capital expenditures	(7,679)	(128,977)	2,795
Receivables exchanged for additional interests in oil and natural gas properties	—	—	8,299
Supplemental cash flow information related to leases:			
Cash paid for amounts included in the measurement of lease liabilities - operating cash flows from operating leases	$ 19,541	$ 14,284	$ 12,768
Right-of-use assets obtained in exchange for new operating lease obligations	4,874	25,469	8,306

(1) Includes $542.6 million, $2.1 billion, and $2.3 billion in non-cash property additions related to the HighPoint, Extraction, and Crestone Peak mergers, respectively, for the year ended December 31, 2021.

(2) Includes $374.9 million, $1.8 billion, and $1.3 billion in non-cash consideration related to the HighPoint, Extraction, and Crestone Peak mergers, respectively, for the year ended December 31, 2021.

NOTE 15 - DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The Company's oil and natural gas activities are located entirely within the United States. Costs incurred in the acquisition, development, and exploration of oil and natural gas properties, whether capitalized or expensed, are summarized below (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Acquisition[1]	$ 437,100	$ 4,861,619	$ 11,296
Development[2][3]	1,044,392	315,746	55,934
Exploration	6,981	7,937	595
Total	$ 1,488,473	$ 5,185,302	$ 67,825

(1) Acquisition costs for unproved properties for the years ended December 31, 2022, 2021, and 2020 were $16.8 million, $648.0 million, and $2.3 million, respectively. There were $420.3 million, $4.2 billion, and $9.0 million in acquisition costs for proved properties for the years ended December 31, 2022, 2021, and 2020, respectively.

(2) Development costs include workover costs of $8.6 million, $2.2 million, and $1.2 million charged to lease operating expense for the years ended December 31, 2022, 2021, and 2020, respectively.

(3) Includes amounts relating to asset retirement obligations of $64.7 million, $13.8 million, and $(1.0) million for the years ended December 31, 2022, 2021, and 2020, respectively.

Suspended Well Costs

The Company did not incur any exploratory well costs during the years ended December 31, 2022, 2021, and 2020.

Reserves

The proved reserve estimates at December 31, 2022, 2021, and 2020 were prepared by Ryder Scott, our third-party independent reserve engineers. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes, and other factors.

All of the Company's oil, natural gas, and natural gas liquids reserves are attributable to properties within the United States. A summary of the Company's changes in quantities of proved oil, natural gas, and natural gas liquids reserves for the years ended December 31, 2022, 2021, and 2020 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)
Balance-December 31, 2019	64,413	212,200	22,161
Extensions, discoveries, and other additions[(1)]	9,376	32,172	3,269
Production	(5,019)	(14,166)	(1,858)
Removed from capital program[(2)]	(14,120)	(33,886)	(3,141)
Purchases of minerals in place	1,430	5,457	570
Revisions to previous estimates[(3)]	(3,287)	33,951	5,110
Balance-December 31, 2020	52,793	235,728	26,111
Extensions, discoveries, and other additions[(1)]	19	103	—
Production	(4,523)	(13,852)	(1,763)
Removed from capital program[(2)]	(12,249)	(43,918)	(4,485)
Purchases of minerals in place	114,379	767,504	89,797
Revisions to previous estimates[(3)]	(6,840)	(57,066)	(3,632)
Balance-December 31, 2021	143,579	888,499	106,028
Extensions, discoveries, and other additions[(1)]	12,408	51,358	6,936
Production	(27,651)	(112,478)	(15,666)
Removed from capital program[(2)]	(105)	(459)	(46)
Purchases of minerals in place	17,479	31,872	4,478
Revisions to previous estimates[(3)]	6,892	8,708	17,104
Balance-December 31, 2022	152,602	867,500	118,834
Proved developed reserves:			
December 31, 2020	24,320	123,220	14,315
December 31, 2021	104,078	748,762	88,967
December 31, 2022	117,768	750,793	102,004
Proved undeveloped reserves:			
December 31, 2020	28,473	112,508	11,796
December 31, 2021	39,501	139,737	17,061
December 31, 2022	34,834	116,707	16,830

(1) During the years ended December 31, 2022, 2021, and 2020, horizontal development resulted in extensions, discoveries, and other additions of 27.9 MMBoe, nominal MMBoe, and 18.0 MMBoe, respectively.

(2) During the years ended December 31, 2022, 2021, and 2020, proved undeveloped reserves were reduced by 0.2 MMBoe, 24.1 MMBoe, and 22.9 MMBoe respectively, primarily due to the removal of proved undeveloped locations from our five-year drilling program.

(3) As of December 31, 2022, the Company revised its proved reserves upward by 25.4 MMBoe. Price-related revisions of 11.8 MMBoe resulted from the increase to SEC prices of $27.11 to $93.67 per Bbl WTI for oil and $2.76 to $6.36 per MMBtu HH for natural gas. The remaining positive revisions of 13.6 MMBoe are primarily driven by updates to well performance forecasts and NGL yields.

As of December 31, 2021, the Company revised its proved reserves downward by 20.0 MMBoe primarily driven by 13.1 MMBoe in negative revisions due to changes in well operating cost methodology, 6.9 MMBoe in negative engineering revisions, and 7.1 MMBoe in negative revisions for fuel gas, interest, shrink, and other minor revisions. The commodity prices at December 31, 2021 increased to $66.56 per Bbl WTI and $3.60 per MMBtu HH from $39.57 per Bbl WTI and $1.99 per MMBtu HH at December 31, 2020, resulting in a partially offsetting positive revision of 7.1 MMBoe.

As of December 31, 2020, the Company revised its proved reserves upward by 7.5 MMBoe primarily driven by 12.3 MMBoe in positive engineering revisions. The commodity prices at December 31, 2020 decreased to $39.57 per Bbl WTI and $1.99 per MMBtu HH from $55.85 per Bbl WTI and $2.58 per MMBtu HH at December 31, 2019, resulting in a partially offsetting negative revision of 4.8 MMBoe.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with authoritative accounting guidance. Future cash inflows were computed by applying prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on current costs and assuming continuation of existing economic conditions.

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

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Future cash flows	$ 23,225,188	$ 14,401,814	$ 2,230,012
Future production costs	(6,490,522)	(5,054,695)	(675,755)
Future development costs	(1,337,494)	(1,107,576)	(530,970)
Future income tax expense	(2,870,178)	(1,465,949)	—
Future net cash flows	12,526,994	6,773,594	1,023,287
10% annual discount for estimated timing of cash flows	(4,599,504)	(2,361,490)	(586,233)
Standardized measure of discounted future net cash flows	$ 7,927,490	$ 4,412,104	$ 437,054

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at period end.

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Beginning of period	$ 4,412,104	$ 437,054	$ 858,147
Sale of oil and gas produced, net of production costs	(2,980,527)	(773,711)	(160,466)
Net changes in prices and production costs	5,016,678	874,155	(641,137)
Net changes in extensions, discoveries, and other additions	638,537	855	(54,269)
Development costs incurred	411,138	108,113	42,325
Changes in estimated development cost	(87,466)	106,788	220,964
Purchases of minerals in place	627,833	4,484,125	12,372
Revisions of previous quantity estimates	619,800	(84,126)	60,754
Net change in income taxes	(991,734)	(915,053)	—
Accretion of discount	532,716	43,705	85,815
Changes in production rates and other	(271,589)	130,199	12,549
End of period	$ 7,927,490	$ 4,412,104	$ 437,054

The average wellhead prices used in determining future net revenues related to the standardized measure calculation as of December 31, 2022, 2021, and 2020 were calculated using the twelve-month arithmetic average of first-day-of-the-month prices inclusive of adjustments for quality and location.

	Year Ended December 31,		
	2022	2021	2020
Oil (per Bbl)	$ 90.28	$ 61.60	$ 34.96
Gas (per Mcf)	$ 5.54	$ 2.60	$ 0.95
Natural gas liquids (per Bbl)	$ 39.05	$ 30.60	$ 6.12

NOTE 16 - SUBSEQUENT EVENTS

On January 24, 2023, the Company entered into a privately-negotiated share purchase agreement with CPPIB Crestone Peak Resources Canada Inc. for the purchase of approximately 4.9 million shares of the Company's common stock at $61.00 per share for a total purchase price of approximately $300 million. The purchase closed on January 27, 2023 and was funded from the Company's cash on hand.

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

None.

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

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2022. The term “disclosure controls and procedures,” as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive and principal financial officers and internal audit function, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2022, our principal executive officer and principal financial officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures. To assist management, we have established an internal audit function to verify and monitor our internal controls and procedures. The Company’s internal control system is supported by written policies and procedures, contains self-monitoring mechanisms, and is audited by the internal audit function. Appropriate actions are taken by management to correct deficiencies as they are identified.

Management’s Assessment of Internal Control Over Financial Reporting

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). The Company’s internal control over financial reporting is a process designed under the supervision of the Company’s Chief Executive Officer and Principal Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the 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 processes may deteriorate.

As of December 31, 2022, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control-Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2022. Management included in its assessment of internal control over financial reporting all consolidated entities.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2022, which is included in the consolidated financial statements in Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in management’s evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the quarter ended December 31, 2022 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Civitas Resources, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Civitas Resources, Inc., and subsidiaries (the "Company") 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 have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2022, of the Company and our report dated February 22, 2023, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte & Touche LLP

Denver, Colorado
February 22, 2023

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

None.

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 will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2022.

Our Board has adopted a Code of Business Conduct and Ethics applicable to all officers, directors, and employees, which is available on our website (www.civitasresources.com) under “Investor Relations” under the “Governance” tab. We will provide a copy of this document to any person, without charge, upon request by writing to us at Civitas Resources, Inc., Investor Relations, 555 17th Street, Suite 3700, Denver, Colorado 80202. We intend to satisfy the disclosure requirement under Item 406(c) of Regulation S-K regarding an amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on our website at the address and the location specified above.

Item 11. ***Executive Compensation*.**

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2022.

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

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2022.

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

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2022.

Item 14. ***Principal Accounting Fees and Services (PCAOB ID No. 34).***

The information required by this item will be incorporated by reference in a future filing with the SEC within 120 days after the end of the fiscal year ended December 31, 2022.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of November 9, 2020, by and among Bonanza Creek Energy, Inc., Boron Merger Sub, Inc. and HighPoint Resources Corporation (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on November 9, 2020)
2.2	Amendment No. 1 to the Agreement and Plan of Merger, by and among Bonanza Creek Energy, Inc., Boron Merger Sub, Inc. and HighPoint Resources Corporation, dated as of January 29, 2021 (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on February 1, 2021)
2.3	Agreement and Plan of Merger, dated as of May 9, 2021, by and among Bonanza Creek Energy, Inc., Raptor Eagle Merger Sub, Inc. and Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 10, 2021).
2.4	Agreement and Plan of Merger, dated as of June 6, 2021, by and among Bonanza Creek Energy, Inc., Raptor Condor Merger Sub 1, Inc., Raptor Condor Merger Sub 2, LLC, Crestone Peak Resources LP, CPPIB Crestone Peak Resources America Inc., Crestone Peak Resources Management LP and Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 2.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 8, 2021).
2.5	Amendment No.1 to Agreement and Plan of Merger, dated as of June 6, 2021, by and among Bonanza Creek Energy, Inc., Raptor Eagle Merger Sub, Inc. and Extraction Oil & Gas, Inc. (incorporated by reference to Exhibit 2.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 8, 2021).
3.1	Third Amended and Restated Certificate of Incorporation of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to Bonanza Creek Energy, Inc.'s Registration Statement on Form 8-A filed on April 28, 2017)
3.2	Certificate of Amendment to the Third Amended and Restated Certificate of Incorporation of Bonanza Creek Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on November 3, 2021).
3.3	Sixth Amended and Restated Bylaws of Civitas Resources, Inc. (incorporated by reference to Exhibit 3.4 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q, File No. 001-35371, filed on October 31, 2022).
4.1	Description of Capital Stock.
4.2	Indenture, dated as of April 1, 2021, by and among Bonanza Creek Energy, Inc., U.S. Bank National Association, as trustee, and the subsidiary guarantors party thereto (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 1, 2021).
4.3	First Supplemental Indenture, dated as of April 1, 2021, by and among Bonanza Creek Energy, Inc., U.S. Bank National Association, as trustee, HighPoint Resources Corporation, HighPoint Operating Corporation and Fifth Pocket Productions, LLC (incorporated by reference to Exhibit 4.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 1, 2021).
4.4	Indenture, dated as of October 13, 2021, by and among Bonanza Creek Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on October 15, 2021).
4.5	First Supplemental Indenture, dated as of November 1, 2021, by and among Civitas Resources, Inc., Computershare Trust Company, N.A., as trustee, and certain guarantor parties thereto (incorporated by reference to Exhibit 4.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).

4.6	Second Supplemental Indenture, dated as of November 1, 2021, by and among Civitas Resources, Inc., U.S. Bank National Association, as trustee, and certain guarantor parties thereto (incorporated by reference to Exhibit 4.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.1	Tranche A Warrant Agreement, dated November 1, 2021, between Civitas Resources, Inc. and Broadridge Corporate Issuer Solutions, Inc. (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.2	Tranche B Warrant Agreement, dated November 1, 2021, between Civitas Resources, Inc. and Broadridge Corporate Issuer Solutions, Inc. (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.3	Registration Rights Agreement, dated April 1, 2021, between Bonanza Creek Energy, Inc., and Franklin Advisers, Inc. (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 1, 2021).
10.4	Registration Rights Agreement, dated as of May 9, 2021, by and between Bonanza Creek Energy, Inc. and Kimmeridge Chelsea, LLC (incorporated by reference to Exhibit 4.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 10, 2021).
10.5	Registration Rights Agreement, dated November 1, 2021, between Civitas Resources, Inc., and the persons identified on Schedule I thereto (incorporated by reference to Exhibit 10.7 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.6*	Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017).
10.7*	Form of Non-Qualified Stock Option Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017).
10.8*	Form of Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 28, 2017).
10.9*	Form of Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018).
10.10*	Form of Independent Director Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on November 6, 2019).
10.11*	Form of Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 22, 2018)
10.12*	Form of Officer Performance Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 9, 2021).
10.13*	Form of NYSE Inducement Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on April 5, 2018).
10.14*	Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 9, 2021).
10.15*	First Amendment to the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.16*	Form of Independent Director Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on August 9, 2021).
10.17*	Form of Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.8 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on October 28, 2021).
10.18*	Form of Non-Officer Restricted Stock Unit Agreement under the Bonanza Creek Energy, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Bonanza Creek Energy, Inc.'s Quarterly Report on Form 10-Q filed on October 28, 2021).

10.19*	Form of Performance Stock Unit Agreement (Absolute TSR) under the Civitas Resources, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Civitas Resources Inc.'s Quarterly Report on Form 10-Q filed on May 5, 2022).
10.20*	Form of Performance Stock Unit Agreement (Relative TSR) under the Civitas Resources, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Civitas Resources Inc.'s Quarterly Report on Form 10-Q filed on May 5, 2022).
10.21*	Form of Restricted Stock Unit Agreement under the Civitas Resources, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.7 to Civitas Resources Inc.'s Quarterly Report on Form 10-Q filed on May 5, 2022).
10.22*	Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Extraction's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on January 20, 2021).
10.23*	Form of Restricted Stock Unit (RSU) Agreement (Time and Performance Vesting) (incorporated by reference to Exhibit 10.7 to Extraction Oil & Gas, Inc.'s Current Report on Form 8-K filed on January 20, 2021).
10.24*†	Global Amendment to Outstanding Awards Under the Civitas Resources, Inc. 2021 Long Term Incentive Plan, Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan, and Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan.
10.25*	Civitas Resources, Inc. Eighth Amended and Restated Executive Change in Control and Severance Plan (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on January 25, 2022).
10.26*	Form of Indemnity Agreement between Civitas Resources, Inc. and the directors and executive officers of Civitas Resources, Inc. (incorporated by reference to Exhibit 10.9 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.27*	Employment Letter Agreement dated June 20, 2019 between Bonanza Creek Energy, Inc. and Sandra Garbiso (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on June 20, 2019).
10.28*	Employment Letter, dated as of June 29, 2022, by and between Civitas Resources, Inc. and Travis L. Counts (incorporated by reference to Exhibit 10.8 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on August 3, 2022).
10.29*	Employee Restrictive Covenants, Proprietary Information and Inventions Agreement, dated as of June 29, 2022, by and between Civitas Resources, Inc. and Travis L. Counts (incorporated by reference to Exhibit 10.9 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on August 3, 2022).
10.30*	Employment Letter, dated as of April 29, 2022, by and between Civitas Resources, Inc. and M. Christopher Doyle (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on May 2, 2022).
10.31*	Employee Restrictive Covenants, Proprietary Information and Inventions Agreement, dated as of April 29, 2022, by and between Civitas Resources, Inc. and M. Christopher Doyle (incorporated by reference to Exhibit 10.3 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on May 2, 2022).
10.32*	Form of Officer Employment/Promotion Letter Agreement (incorporated by reference to Exhibit 10.22 to Bonanza Creek Energy, Inc.'s Annual Report on Form 10-K filed February 28, 2020)
10.33	Amended and Restated Credit Agreement, dated as of November 1, 2021, between Civitas Resources, Inc., as borrower, JPMorgan Chase Bank, N.A., as the administrative agent, and a syndicate of financial institutions, as lenders (incorporated by reference to Exhibit 10.5 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.34	First Amendment to Amended and Restated Credit Agreement, among Civitas Resources, Inc., the guarantors party thereto, the lenders party thereto and JPMorgan Chase Bank, N.A., as the administrative agent (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on December 22, 2021).
10.35	Second Amendment to Amended and Restated Credit Agreement, among Civitas Resources, Inc., the guarantors party thereto, the lenders party thereto and JPMorgan Chase Bank, N.A., as the administrative agent (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on April 21, 2022).

10.36	Letter Agreement, dated as of May 19, 2021, by and among Bonanza Creek Energy, Inc., the Administrative Agent and the Lenders under that certain Credit Agreement, dated as of December 7, 2018 (as amended or restated from time to time) (incorporated by reference to Exhibit 10.1 to Bonanza Creek Energy, Inc.'s Current Report on Form 8-K filed on May 21, 2021).
10.37*	Director Compensation Program, dated November 1, 2021 (incorporated by reference to Exhibit 10.10 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.38	Membership Interest Purchase Agreement, dated as of January 31, 2022, by and among Civitas Resources, Inc., Bison Oil & Gas Partners II, LLC, and Bison Oil & Gas II, LLC (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on February 1, 2022).
10.39	First Amendment to Membership Interest Purchase Agreement, dated as of February 27, 2022, by and among Civitas Resources, Inc., Bison Oil & Gas Partners II, LLC, and Bison Oil & Gas II, LLC. (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on March 2, 2022).
10.40	Severance, Release and Consulting Agreement, dated January 31, 2022, by and between Civitas Resources, Inc. and Eric T. Greager (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on February 1, 2022).
10.41*	Severance and Release Agreement, dated as of July 22, 2022, by and between Civitas Resources, Inc. and Dean Tinsley (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on July 25, 2022).
10.42*	Transition and Retirement Agreement, dated as of June 29, 2022, by and between Civitas Resources, Inc. and Cyrus ("Skip") D. Marter IV (incorporated by reference to Exhibit 10.1 To Civitas Resources, Inc.'s Current Report on Form 8-K filed on June 29, 2022).
10.43	Board Observer and Confidentiality Agreement, dated November 1, 2021, between Civitas Resources, Inc. and CPPIB Crestone Peak Resources Canada Inc. (incorporated by reference to Exhibit 10.8 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 3, 2021).
10.44	Share Purchase Agreement, dated January 24, 2023, between Civitas Resources, Inc. and CPPIB Crestone Peak Resources Canada Inc. (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on January 24, 2023).
21.1†	List of subsidiaries
23.1†	Consent of Deloitte & Touche LLP
23.2†	Consent of Independent Petroleum Engineers, Ryder Scott Company, L.P.
31.1†	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
31.2†	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
32.1†	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
32.2†	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
99.1†	Report of Independent Petroleum Engineers, Ryder Scott Company, L.P., for reserves as of December 31, 2022
101.INS†	XBRL Instance Document
101.SCH†	XBRL Taxonomy Extension Schema
101.CAL†	XBRL Taxonomy Extension Calculation Linkbase
101.DEF†	XBRL Taxonomy Extension Definition Linkbase
101.LAB†	XBRL Taxonomy Extension Label Linkbase
101.PRE†	XBRL Taxonomy Extension Presentation Linkbase
104	Cover Page Interactive Data File (formatted as Inline XBRL)

* Management Contract or Compensatory Plan or Arrangement
† Filed or furnished herewith

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.

		CIVITAS RESOURCES, INC.	
Date:	February 22, 2023	By:	/s/ Chris Doyle
			Chris Doyle, *President and Chief Executive Officer (principal executive officer)*

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Chris Doyle, Marianella Foschi, Travis L. Counts, and Sandi K. Garbiso 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 annual report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:	February 22, 2023	By:	/s/ Chris Doyle
			Chris Doyle, *President and Chief Executive Officer (principal executive officer)*
		By:	/s/ Marianella Foschi
			Marianella Foschi, *Chief Financial Officer (principal financial officer)*
		By:	/s/ Sandi K. Garbiso
			Sandi K. Garbiso, *Chief Accounting Officer and Treasurer (principal accounting officer)*
		By:	/s/ Benjamin Dell
			Benjamin Dell, *Chairman of the Board*
		By:	/s/ Morris R. Clark
			Morris R. Clark, *Director*
		By:	/s/ Carrie M. Fox
			Carrie M. Fox, *Director*
		By:	/s/ Carrie Hudak
			Carrie Hudak, *Director*
		By:	/s/ Brian Steck
			Brian Steck, *Director*
		By:	/s/ James Trimble
			James Trimble, *Director*
		By:	/s/ Howard A. Willard, III
			Howard A. Willard, III, *Director*
		By:	/s/ Jeffrey E. Wojahn
			Jeffrey E. Wojahn, *Director*

GLOBAL AMENDMENT TO
OUTSTANDING AWARDS
UNDER THE CIVITAS RESOURCES, INC. 2021 LONG TERM INCENTIVE PLAN, EXTRACTION OIL & GAS, INC. 2021 LONG TERM INCENTIVE PLAN, AND BONANZA CREEK ENERGY, INC. 2017 LONG TERM INCENTIVE PLAN

This Global Amendment to outstanding awards under the Civitas Resources, Inc. 2021 Long Term Incentive Plan, Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan, and Bonanza Creek Energy, Inc. 2017 Long Term Incentive Plan (collectively, as amended from time to time, the "LTIPs") is hereby adopted by Civitas Resources, Inc., a Delaware corporation (the "Company"), as of October 26, 2022 (the "Effective Date"). Capitalized terms used but not defined herein shall have the meanings assigned to such terms in the applicable LTIP or, if not defined in the applicable LTIP, the meanings assigned to such terms in the applicable outstanding award agreements and other documentation (the "Award Documents").

WHEREAS, pursuant to each of the LTIPs and the Award Documents, the terms and conditions of the Award Documents may be amended without the consent of any grantee, provided that such amendment does not materially impair or adversely affect, as applicable, the grantee's rights under the award subject to such amendment

WHEREAS, awards granted under the LTIPs to non-employee directors of the Company (the "Non-Employee Director Awards" and, the applicable Award Documents, the "Non-Employee Director Award Documents") provide for full accelerated vesting of the Non-Employee Director Award immediately upon a termination of the applicable non-employee director's service due to such non-employee director's death or Disability; and

WHEREAS, the Company desires to amend each outstanding Award Document other than the Non-Employee Director Award Documents (the "Subject Award Documents" and, the outstanding awards subject to the Subject Award Documents, the "Subject Awards") to provide for accelerated vesting upon a termination of the applicable grantee's service due to such grantee's death or Disability as set forth herein.

NOW, THEREFORE, in consideration of the foregoing, effective as of the Effective Date, the Subject Award Documents are hereby amended as follows:

1. Notwithstanding anything to the contrary in any Subject Award Document, with respect to each Subject Award, if the grantee's service terminates due to death or Disability, the entire unvested portion of such Subject Award shall immediately vest in full upon such termination (with any Subject Awards that vest based on one or more performance conditions vesting at the "target" level performance). For purposes of the immediately preceding sentence, if there is no definition of "Disability" (or a similar term) in the Subject Award Document and applicable to the grantee, the term "Disability" means that (a) the grantee has become eligible to receive disability benefits under either the Social Security Disability Insurance program or the Company's long-term disability plan, if any, or (b) the Company, based on the written report of a qualified physician designated by the Company's insurers, determines (after a complete physical examination of the grantee at any time after the grantee has been absent from work for 90 or more consecutive calendar days) that the grantee has become physically and/or mentally incapable of performing the grantee's essential job functions with or without reasonable accommodation as required by law due to injury, illness, or other incapacity (physical or mental).

2. Except as expressly amended hereby, the Subject Award Documents and Subject Awards shall remain in full force and effect and are specifically ratified and reaffirmed.

Civitas Resources, Inc.

By:	/s/ Travis L. Counts
Name:	Travis L. Counts
Title:	Chief Legal Officer and Secretary

Exhibit 21.1

Subsidiaries of Civitas Resources, Inc., a Delaware corporation

SUBSIDIARIES OF CIVITAS RESOURCES, INC. (f/k/a BONANZA CREEK ENERGY, INC.):
- BONANZA CREEK ENERGY OPERATING COMPANY, LLC, a Delaware limited liability company
- HIGHPOINT RESOURCES CORPORATION, a Delaware corporation
- EXTRACTION OIL & GAS, INC., a Delaware corporation
- RAPTOR CONDOR MERGER SUB 2, LLC, a Delaware limited liability company
- CIVITAS NORTH, LLC, a Colorado limited liability company

SUBSIDIARIES OF BONANZA CREEK ENERGY OPERATING COMPANY, LLC:
- ROCKY MOUNTAIN INFRASTRUCTURE, LLC, a Delaware limited liability company
- HOLMES EASTERN COMPANY, LLC, a Delaware limited liability company

SUBSIDIARIES OF HIGHPOINT RESOURCES CORPORATION:
- HIGHPOINT OPERATING CORPORATION, a Delaware corporation

SUBSIDIARIES OF HIGHPOINT OPERATING CORPORATION:
- FIFTH POCKET PRODUCTION, LLC, a Colorado limited liability company

SUBSIDIARIES OF EXTRACTION OIL & GAS, INC.:
- EXTRACTION FINANCE CORP., a Delaware corporation
- MOUNTAINTOP MINERALS, LLC, a Delaware limited liability company
- TABLE MOUNTAIN RESOURCES, LLC, a Delaware limited liability company
- NORTHWEST CORRIDOR HOLDINGS, LLC, a Delaware limited liability company
- XTR MIDSTREAM, LLC, a Delaware limited liability company
- 7N, LLC, a Delaware limited liability company
- 8 NORTH, LLC, a Delaware limited liability company
- AXIS EXPLORATION, LLC, a Delaware limited liability company
- XOG SERVICES, LLC, a Delaware limited liability company

SUBSIDIARIES OF RAPTOR CONDOR MERGER SUB 2, LLC:
- CRESTONE PEAK RESOURCES GP INC., a Delaware corporation
- CRESTONE PEAK RESOURCES LP, a Delaware limited partnership
- CRESTONE PEAK RESOURCES LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES ACQUISITION COMPANY I LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES OPERATING LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES MIDSTREAM LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES HOLDINGS LLC, a Delaware limited liability company
- COLLEGIATE HOLDINGS LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES WATKINS MIDSTREAM LLC, a Delaware limited liability company
- CRESTONE PEAK RESOURCES WATKINS HOLDINGS LLC, a Delaware limited liability company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-263753 on Form S-3 and Nos. 333-217545, 333-229431, 333-257295 and 333-260881 on Form S-8 of our reports dated February 22, 2023, relating to the financial statements of Civitas Resources, Inc. and its subsidiaries (the “Company”) and the effectiveness of the Company’s internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2022.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 22, 2023

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580

633 SEVENTEENTH STREET, SUITE 1700   DENVER, COLORADO 80202   (303) 339-8110

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Civitas Resources, Inc. for the year ended December 31, 2022. We further consent to the incorporation by reference thereof into Civitas Resources, Inc.'s Registration Statements on Form S-3 (Registration No. 333-263753) and Form S-8 (Registration Nos. 333-217545, 333-229431, 333-257295 and 333-260881).

By: /s/Ryder Scott Company, L.P.
RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Denver, Colorado
February 22, 2023

Exhibit 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13a- 14(a)

I, Chris Doyle, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2022 of Civitas Resources, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: February 22, 2023

/s/ Chris Doyle

Chris Doyle

President and Chief Executive Officer (principal executive officer)

Exhibit 31.2

CERTIFICATION OF THE PRINCIPAL FINANCIAL OFFICER PURSUANT TO RULE 13a- 14(a)

I, Marianella Foschi, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2022 of Civitas Resources, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: February 22, 2023

/s/ Marianella Foschi
Marianella Foschi
Chief Financial Officer (principal financial officer)

Exhibit 32.1

Certification of the Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Civitas Resources, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Chris Doyle, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge:

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

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

Date: February 22, 2023

/s/ Chris Doyle
Chris Doyle
President and Chief Executive Officer (principal executive officer)

Exhibit 32.2

Certification of the Principle Financial Officer
Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Civitas Resources, Inc. (the “Company”) on Form 10-K for the year ended December 31, 2022 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Marianella Foschi, Chief Financial Officer, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

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

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

Date: February 22, 2023

/s/ Marianella Foschi
Marianella Foschi
Chief Financial Officer (principal financial officer)

CIVITAS RESOURCES, INC.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2022

/s/ Scott J. Wilson	/s/ Edward M. Polishuk
Scott J. Wilson, P.E., MBA	Edward M. Polishuk
Colorado License No. 36112	Senior Petroleum Evaluator
Senior Vice President	

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 31, 2023

Civitas Resources, Inc.
555 17th Street, Suite 3700
Denver, Colorado 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Civitas Resources, Inc. (Civitas) as of December 31, 2022. The subject properties are located in the state of Colorado. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 31, 2023 and presented herein, was prepared for public disclosure by Civitas in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Civitas as of December 31, 2022.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Civitas Resources, Inc.
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	101,607	16,161	34,834	152,602
Plant Products – Mbbl	94,790	7,214	16,830	118,834
Gas – MMcf	698,489	52,304	116,707	867,500
Income Data ($M)				
Future Gross Revenue	$16,420,326	$2,022,689	$4,549,920	$22,992,935
Deductions	5,066,745	777,921	1,751,093	7,595,759
Future Net Income (FNI)	$11,353,581	$1,244,768	$2,798,827	$15,397,176
Discounted FNI @ 10%	$ 7,291,849	$ 872,052	$1,670,377	$ 9,834,278

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the area in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Civitas. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, plant treatment costs, ad valorem taxes, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 79 percent and gas reserves account for the remaining 21 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2022 Total Proved
8	$10,564,532
9	$10,184,127
12	$ 9,212,738
15	$ 8,436,561

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined under the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in status category for wells shut-in due to offset completion activity or waiting on facility connection, and wells waiting for abandonment.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Civitas's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Civitas's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Civitas owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. In general, the proved producing reserves were estimated by performance methods. These performance methods include decline curve analysis, which utilized extrapolations of historical production data available through December 2022 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Civitas and were considered sufficient for the purpose thereof.

The proved developed non-producing reserves were estimated by historical performance prior to the wells being shut-in or by analogy. The proved undeveloped reserves included herein, were estimated by analogy. The data utilized from the shut-in wells and from the analogues were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Civitas has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Civitas with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Civitas. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Civitas. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling and completing wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

Civitas furnished us with the above mentioned average benchmark prices in effect on December 31, 2022. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Civitas. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Civitas to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$93.67/bbl	$90.28/bbl
	NGLs	WTI Cushing	$93.67/bbl	$39.05/bbl
	Gas	Henry Hub	$6.358/MMBTU	$5.54/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations

Costs

Operating costs for the leases and wells in this report were furnished by Civitas and are based on the operating expense reports of Civitas and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For Civitas operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-Civitas-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Civitas. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Civitas and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Civitas were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Civitas's plans to develop these reserves as of December 31, 2022. The implementation of Civitas's development plans as presented to us and incorporated herein is subject to the approval process adopted by Civitas's management. As the result of our inquiries during the course of preparing this report, Civitas has informed us that the development activities included herein have been subjected to and received the internal approvals required by Civitas's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Civitas. Civitas has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Civitas has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Civitas were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Civitas. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Civitas.

Civitas makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Civitas has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of Civitas, of the references to our name, as well as to the references to our third party report for Civitas, which appears in the December 31, 2022 annual report on Form 10-K of Civitas. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Civitas.

We have provided Civitas with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Civitas and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Scott J. Wilson

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President **[SEAL]**

/s/ Edward M. Polishuk

Edward M. Polishuk
Senior Petroleum Evaluator

SJW-EMP (LPC)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co-Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, Civitas method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized Civitas technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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

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

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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

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

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

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