CIVITAS

Disrupting ENERGY for good

2023 ANNUAL REPORT

Our Strategic Pillars

1 Generate Free Cash Flow

- → Capital efficient asset base
- → Low operating costs
- → Minimize reinvestment rates

2 Maintain Premier Balance Sheet

- → 0.75x net leverage target
- → Minimal long-term commitments
- → Deep financial liquidity

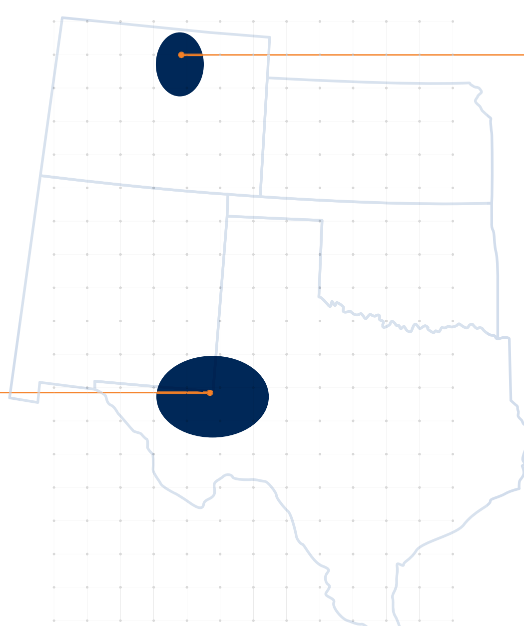
3 Return Cash to Shareholders

- → Established framework
- → Base and variable dividend
- → Opportunistic share buybacks

4 Demonstrate ESG Leadership

- → Committed to sustainability
- → 1st carbon neutral (Scope 1 and 2) E&P in Colorado
- → Target carbon neutral in Permian in 2025

Our High-quality Portfolio



DJ Basin

- → **454K** net acres
- → **780** locations
- → **~165** MBoe/d production
- → **352** MMBoe proved reserves

Permian Basin

- → **112K** net acres
- → **1,120** locations
- → **~170** MBoe/d production
- → **346** MMBoe proved reserves*

* Does not include reserves for the Vencer Energy acquisition, which closed January 2, 2024.

Chris Doyle

President and Chief Executive Officer

Fellow Shareholders

The year 2023 was transformational for our Company. We took strategic actions to add scale and diversify our asset base, which led us to acquiring significant new positions in the Permian Basin at attractive valuations. These transactions established operational scale in a second premier oil basin and doubled our proved reserves, daily production, and the depth of our high-quality drilling inventory. These new assets complement our legacy DJ Basin position, solidifying our ability to create long-term, differentiated value for our shareholders. Through this transformation, we stayed true to our Strategic Pillars and today we are a remarkably different and stronger enterprise.

2023

We achieved all key deliverables under our 2023 business plan and recorded solid financial and operating results.

- **Returned nearly $1 billion to shareholders**, or more than 15% of our market capitalization, through our industry-leading shareholder return program;
- **Net income was $784 million**, or more than $9 per diluted share, and net cash provided by operating activities was $2.2 billion;
- **Full-year capital investments were in line with plan** at less than $1.4 billion;
- **Production exceeded expectations**, averaging more than 212 MBoe/d;
- **Maintained a strong balance sheet** and our credit rating was upgraded by all rating agencies;
- **Demonstrated continued Sustainability leadership**, reducing our DJ Basin total recordable incident rate, spill count, and emissions;
- **Increased proved reserves nearly 70%** to 698 MMBoe (excluding impact from the Vencer Energy acquisition), reflecting the impact of large Permian acquisitions, as well as positive extensions, discoveries, and additions to existing reserves.

2024

The objectives of our 2024 outlook are aligned with our Strategic Pillars – maximize free cash flow, enhance our strong balance sheet, continue our industry-leading shareholder return program, and lead in ESG.

We remain focused on value and returns, not production growth. Accordingly, our 2024 capital investment plan has been optimized, as we reduced our capex $150 million from our prior outlook and maintained our production expectations. Total investments are estimated at $1.8–$2.1 billion.

Key 2024 metrics

$1.8–2.1B
2024E Capital Program
60% Permian
40% DJ Basin

325–345 MBoe/d
2024E Sales Volumes

$6 per share
Anticipated 2024 Dividends
@ $75/Bbl oil

Our track record in the DJ Basin proves that assets are better in our hands, and our teams are incredibly excited about the prospects of lowering costs, enhancing returns, and decreasing emissions in the Permian Basin assets also. We look forward to reporting on our progress as 60% of our capital will be allocated to our Permian Basin assets this year.

Activity in the DJ Basin this year will largely focus on the Watkins development area where recent results support our view for higher resource recovery across much of our remaining development position. We have been a leading operator in the DJ Basin for over a decade, and our knowledge of the basin combined with our track record of continuous improvement consistently result in operational excellence.

We expect to fund this year's capital program using about 50% of our cash flow. This low reinvestment rate is a testament to the quality of our asset base, capital discipline, and a continued focus on creating sustainable capital efficiencies. Recent commodity prices indicate we will generate approximately $1.3 billion in free cash flow in 2024.

About half of our projected free cash is earmarked for our peer-leading dividend program, which would potentially result in full-year dividends for 2024 of about $6 per share. Civitas has an unwavering commitment to a strong balance sheet, and we will continue to progress toward our long-term leverage target is 0.75x. The ongoing sale of non-core assets is expected to further aid our financial position and we expect to divest $300 million in assets by midyear. We also have approximately $425 million remaining under our share buyback authorization, and we will be opportunistic in acquiring our shares.

Civitas has a differentiated story today, reflecting our significant accomplishments over the last two years. We have operational scale, asset durability and diversity, a strong capital structure, and a leading shareholder return program. This is a winning combination.

Our business strategy is being executed by some of the most talented men and women in the energy business, and it's an honor to lead them every day. Thank you for your investment in our Company.

Sincerely,

Chris Doyle
President and Chief Executive Officer

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, 2023

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, 2023, based upon the closing price of $69.37 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $3.6 billion. Excludes approximately 28.6 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 23, 2024: 101,020,532

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, 2023, as incorporated by reference into Part III of this report for the year ended December 31, 2023.

CIVITAS RESOURCES, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2023

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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:

- our 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 pursue potential future capital management activities such as share repurchases, paying dividends on our common stock at their current level or at all, or additional mechanisms to return excess capital to our stockholders;
- 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;
- 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;
- plans and expectations with respect to our recent acquisitions and the anticipated impact of the recent acquisitions on our results of operations, financial position, future growth opportunities, reserve estimates, and competitive position;
- the results, effects, benefits, and synergies of other 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. Risk Factors*" of this Annual Report on Form 10-K;
- declines or volatility in the prices we receive for our crude oil, natural gas, and NGL;
- 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;
- our ability to identify and select possible additional acquisition and disposition opportunities;
- the effects of disruption of our operations or excess supply of crude oil and natural gas and other effects of world health events and the actions by certain crude 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 crude 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, health, and safety regulation and regulations addressing climate change);
- environmental, health, and safety 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 crude oil and natural gas processing facilities;
- competition in the oil and gas industry;
- management's ability to execute our plans to meet our goals;
- unforeseen difficulties encountered in operating in new geographic areas;
- 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 crude oil, natural gas, and NGL we produce, and to sell the crude oil, natural gas, and NGL 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 (including the current events related to the Israel-Palestine conflict), South America, and Russia (including the current events involving Russia and Ukraine), and other sustained military campaigns or acts of terrorism or sabotage; 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 "*Part I - Item 1A. Risk Factors*" and "*Part II - 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 CRUDE 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 our business or any of our subsidiaries, or (c) any other of our assets or any of our subsidiaries 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.

"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.

"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.

"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 Btu.

"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(s).

"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.

"Percentage-of-proceeds." A processing contract where the processor receives a percentage of the sold outlet stream, dry gas, NGL, 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." 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 NGL 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 Crude Oil and Natural Gas Terms*" above. Throughout this document, we make statements that may be classified as "forward-looking." Please refer to "*Information Regarding Forward-Looking Statements*" 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 crude oil and associated liquids-rich natural gas primarily in the Denver-Julesburg Basin in Colorado (the "DJ Basin") and the Permian Basin in Texas and New Mexico. These basins are among the major producing basins in the United States and are characterized by extensive production histories, mature infrastructure, long reserve lives, multiple producing horizons, enhanced recovery potential, and a large number of operators.

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. We are also actively pursuing projects designed to reduce or eliminate greenhouse gas ("GHG") emissions associated with our operations as an initial focus, and then aim to address remaining GHG emissions through the retirement of certified carbon credits and renewable energy credits.

Our Business Strategies

Our primary objective is to maximize stockholder 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.*** We have a scaled, high-quality asset base with ample low-breakeven inventory that provides us with the ability to generate significant Free Cash Flow, a non-GAAP financial measure, across two premier basins. We pursue value-accretive investments to enhance our ability to deliver incremental returns to our stockholders.

- ***Maintain a premier balance sheet.*** A strong balance sheet, focus on cost control, and minimization of long-term commitments are critical to managing risk and achieving success within fluctuating market conditions.

- ***Return cash to stockholders.*** We prioritize consistently returning cash to stockholders through our published dividend framework in a variety of commodity price environments. We strive towards returning one of the industry's premier payout ratios, with an approximate 11% dividend yield during 2023. Additionally, we seek opportunistic buybacks of our stock and repurchased approximately $320 million of our stock during 2023.

- ***Demonstrate ESG Leadership.*** We have integrated ESG initiatives throughout our organization.

  Environment. We are committed to making meaningful progress on reducing the GHG emissions of our operations by targeting high GHG impact emissions elimination projects, leveraging capital investment to help reduce operational methane emissions and proactively address emerging regulatory topics. 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. Civitas is committed to emissions reduction in its 2023 Permian Basin acquisitions in 2024 and carbon neutrality at the beginning of 2025.

  Social. The safety of our communities, employees, and contractors is a top priority. We have developed, promoted and implemented best practices around safety, and we continue to innovate and enhance those practices.

Governance. Our Board of Directors (the "Board") has a dedicated ESG Committee to provide oversight and support of our environmental, health, safety, regulatory, and compliance policies social governance, sustainability, and other related public policy matters relevant to us.

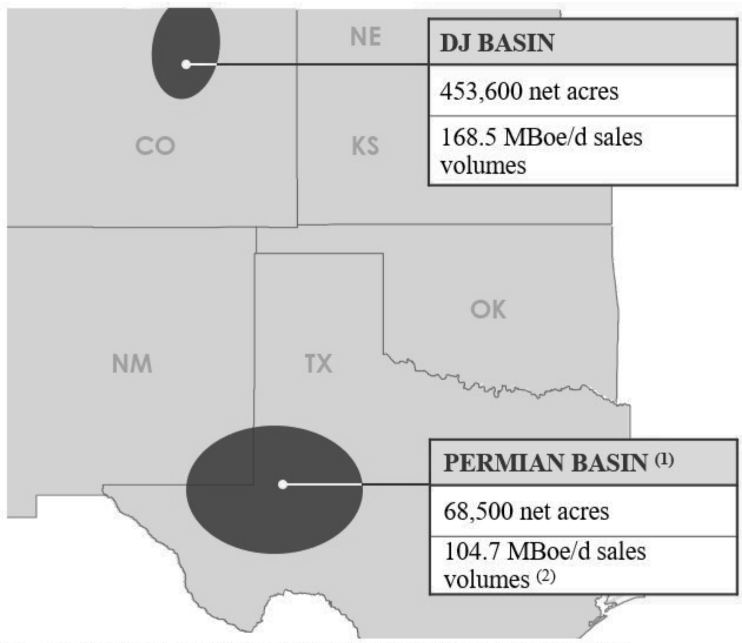
Significant Developments in 2023

Diversify, Scale, and Extend Our Asset Base. On August 2, 2023, we completed the acquisition of Hibernia Energy III Holdings, LLC and Hibernia Energy III-B Holdings, LLC (the "Hibernia Acquisition") and Tap Rock AcquisitionCo, LLC, Tap Rock Resources II, LLC, and Tap Rock NM10 Holdings, LLC (the "Tap Rock Acquisition"). These acquisitions, along with other minor asset acquisitions, repositioned our operations by adding high-quality and scaled assets in the Permian Basin, resulting in the addition of approximately 68,500 net acres and approximately 106,000 Boe per day for the quarter ended December 31, 2023. The Hibernia Acquisition included approximately 38,000 net acres in the Midland Basin and certain related oil and gas assets in exchange for aggregate consideration of approximately $2.2 billion in cash, subject to certain customary purchase price adjustments. The Tap Rock Acquisition included approximately 30,000 net acres in the Delaware Basin and certain related oil and gas assets in exchange for aggregate consideration of approximately $1.5 billion in cash and 13.5 million shares of our common stock, subject to certain customary purchase price adjustments. Furthermore, on October 3, 2023, we entered into a purchase and sale agreement with Vencer Energy, LLC to acquire certain oil and gas properties, interests, and related assets (the "Vencer Acquisition"), which closed on January 2, 2024. The Vencer Acquisition included approximately 44,000 net acres and approximately 62,000 Boe per day in the Midland Basin in exchange for aggregate consideration of approximately $1.0 billion in cash and 7.3 million shares of our common stock paid at the closing of the Vencer Acquisition and $550.0 million in cash to be paid on or before January 3, 2025. We believe that the acquisition of these high-quality assets provides flexibility in capital allocation and makes us a stronger and more sustainable enterprise.

Capital Returns. We posted strong financial results, including net income of $784.3 million and cash flow from operating activities of $2.2 billion, underpinned by well performance from our high-return development projects. We met all key deliverables under our 2023 business plan, delivering full-year production and capital investments in line with guidance. We invested approximately 60% of our cash flow from operating activities into the development of our crude oil and natural gas properties, allowing us to continue to return significant cash to stockholders. During 2023, we declared $668.7 million through base and variable dividends, including $149.1 million paid in December 2023. In 2023, we repurchased approximately 5.2 million shares of our common stock at an average price of $61.21 per share.

Excelling in ESG. We achieved our annual safety target, advanced critical environmental, health, and safety objectives, integrated data management systems to improve productivity and align work processes, and continued to cultivate a results-driven employee culture focused on continuous improvement. We completed our comprehensive retrofit program of natural gas pneumatic devices, which have historically constituted a significant portion of our Scope 1 GHG emissions. The emissions reduction from this project is equivalent to removing over 3,500 light-duty trucks from the roads. Additionally, we began the process of plugging the wells in our voluntary orphaned well abandonment program announced in 2022, with anticipated completion in 2025.

Our Operations



(1) Excludes net acreage and sales volumes associated with the Vencer Acquisition, which closed on January 2, 2024.
(2) Average sales volumes per day for the Permian Basin is calculated based on the number of days between the closing of the Hibernia Acquisition and the Tap Rock Acquisition on August 2, 2023 and December 31, 2023.

Our operations are concentrated in the DJ Basin and Permian Basin as described above. The following table summarizes estimated proved reserves, net sales volumes, and costs incurred for the year ended December 31, 2023 for these areas:

	DJ Basin	Permian Basin	Total
Proved reserves			
Crude oil (MBbl)	132,860	139,945	272,805
Natural gas (MMcf)	729,425	590,877	1,320,302
NGL (MBbl)	97,466	107,477	204,943
Total proved reserves (MBoe) [(1)]	351,897	345,902	697,799
Relative percentage	50 %	50 %	100 %
Proved developed %	87 %	68 %	78 %
Net sales volumes			
Crude oil (MBbl)	28,925	7,801	36,726
Natural gas (MMcf)	110,339	23,482	133,821
NGL (MBbl)	14,199	4,201	18,400
Total net sales volumes (MBoe) [(1)]	61,514	15,916	77,430
Average daily equivalents (MBoe/d) [(1)(2)]	168.5	104.7	273.2
Relative percentage	62 %	38 %	100 %

(1) Amounts may not calculate due to rounding.
(2) Average sales volumes per day for the Permian Basin is calculated based on the number of days between the closing of the Hibernia Acquisition and the Tap Rock Acquisition on August 2, 2023 and December 31, 2023.

Total proved reserves as of December 31, 2023 increased 68% from December 31, 2022. Average daily equivalent sales volumes increased 61% for the combination of the year ended December 31, 2023 for the DJ Basin and the period between the closing of the Hibernia Acquisition and the Tap Rock Acquisition on August 2, 2023 and December 31, 2023, compared with the year ended December 31, 2022, primarily as a result of the Hibernia Acquisition and the Tap Rock Acquisition.

DJ Basin. Our DJ Basin assets are comprised of approximately 453,600 net acres located primarily in Weld, Arapahoe, Adams, Boulder, and Broomfield counties, Colorado. Our operations in the DJ Basin primarily target the Niobrara and Codell formations. We believe our position allows us to control the pace, costs, and completion techniques used in the development of our reserves. In 2023, we averaged 2.0 drilling rigs and 1.8 completion crews in the DJ Basin that allowed us to drill 107 gross (90.6 net) operated wells, complete 126 gross (107.8 net) operated wells, and turn to sales 148 gross (124.3 net) operated wells.

Net sales volumes in the DJ Basin for the year ended December 31, 2023, was 61,514 MBoe, a 1% decrease from 62,063 MBoe for the year ended December 31, 2022. Estimated proved reserves in the DJ Basin decreased 15% to 351,897 MBoe at December 31, 2023, from 416,019 MBoe at December 31, 2022.

Permian Basin. Our Permian Basin assets are comprised of approximately 68,500 net acres located primarily in Upton, Reagan, Ward, and Reeves counties, Texas and Eddy and Lea counties, New Mexico. Our operations in the Permian Basin primarily target the Spraberry and Wolfcamp formations of the Midland Basin and the Wolfcamp and Bone Spring formations of the Delaware Basin, both of which are part of the larger Permian Basin in Texas and New Mexico. We believe our position allows us to control the pace, costs, and completion techniques used in the development of our reserves. Subsequent to the acquisition of the Permian assets in August 2023, we averaged 5.6 drilling rigs and 2.7 completion crews that allowed us to drill 55 gross (44.4 net) operated wells, complete 56 gross (48.9 net) operated wells, and turn to sales 78 gross (66.0 net) operated wells in the Permian Basin.

Net sales volumes in the Permian Basin for the year ended December 31, 2023, was 15,916 MBoe. Estimated proved reserves in the Permian Basin were 345,902 MBoe at December 31, 2023.

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 crude oil and natural gas producing activities. Our reserve estimates do not include probable or possible reserves. For a definition of proved reserves under the SEC rules, please see "*Glossary of Crude Oil and Natural Gas Terms*" included at 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 by category as of December 31, 2023, 2022, and 2021. All of our estimated proved reserves are located in the continental United States. 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,		
	2023	2022	2021
Reserves volumes:			
Estimated proved reserves:			
Crude oil (MBbl)	272,805	152,602	143,579
Natural gas (MMcf)	1,320,302	867,500	888,499
NGL (MBbl)	204,943	118,834	106,028
Total proved reserves (MBoe)(1)	697,799	416,019	397,690
Percent crude oil and liquids	68 %	65 %	63 %
Reserves data (in millions):			
Standardized measure	$ 8,269	$ 7,927	$ 4,412
Estimated undiscounted future net cash flows	12,937	12,527	6,774
PV-10(2)	9,380	9,834	5,327
12-month trailing average prices(3):			
Crude oil (per Bbl)	$ 78.22	$ 93.67	$ 66.56
Natural gas (per MMBtu)	2.64	6.36	3.60

(1) Amounts may not calculate due to rounding.
(2) PV-10 is a non-GAAP financial measure. See "*Part II - Item 7. Non-GAAP Financial Measures - Reconciliation of Proved Reserves PV-10 to Standardized Measure*" of this report.
(3) The prices used in the calculation of proved reserves estimates reflect the unweighted arithmetic average of the first-day-of-the-month price of each month within the trailing 12-month period in accordance with SEC rules. We then adjust these prices to reflect appropriate quality and location differentials over the period in estimating our proved reserves.

The table below sets forth information regarding our estimated proved reserves by category and operating region as of December 31, 2023:

Operating Region/Area	Crude Oil (MBbls)	Natural Gas (MMcf)	NGL (MBbls)	Crude Oil Equivalent (MBoe)	Percent
Proved developed reserves:					
DJ Basin	105,351	665,843	89,250	305,575	56 %
Permian Basin	94,234	411,378	72,867	235,664	44 %
Total proved developed reserves	199,585	1,077,221	162,117	541,239	100 %
Proved undeveloped reserves:					
DJ Basin	27,509	63,582	8,216	46,322	30 %
Permian Basin	45,711	179,499	34,610	110,238	70 %
Total proved undeveloped reserves	73,220	243,081	42,826	156,560	100 %
Proved reserves:					
DJ Basin	132,860	729,425	97,466	351,897	50 %
Permian Basin	139,945	590,877	107,477	345,902	50 %
Total proved reserves(1)	272,805	1,320,302	204,943	697,799	100 %

(1) Items may not recalculate due to rounding.

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, 2023 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, we book 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, we utilize 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, 2023, we had 305 gross proved undeveloped locations compared to 201 as of December 31, 2022. Our gross proved undeveloped drilling locations as of December 31, 2023 have an average lateral length of approximately two miles.

Total estimated proved reserves at December 31, 2023 increased 281.8 MMBoe, or 68%, to 697.8 MMBoe when compared to December 31, 2022. A summary of our changes in quantities of total proved reserves for the year ended December 31, 2023 is as follows:

	Net Reserves (MBoe)
Beginning of year	416,019
Extensions, discoveries, and other additions	21,513
Production	(77,430)
Divestiture of reserves	(1,940)
Removed from capital program	(4,758)
Acquisition of reserves	372,377
Revisions to previous estimates	(27,982)
End of year	697,799

The 372.4 MMBoe of acquisition of reserves is comprised of 140.6 MMBoe acquired in the Tap Rock Acquisition, 214.5 MMBoe acquired in the Hibernia Acquisition, and 6.8 MMBoe acquired in other minor asset acquisitions in the Permian Basin. The remaining 10.5 MMBoe is comprised of various acquisitions and acreage exchanges in our operated wells in the DJ Basin. The 21.5 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 17.2 MMBoe through 48 gross proved undeveloped location additions and 4.3 MMBoe of new proved developed reserves that did not have any associated proved undeveloped reserves recorded as of December 31, 2022. The 28.0 MMBoe negative revision of proved reserves as compared to previous estimates was the result of: (i) negative price-related revisions of 11.1 MMBoe that resulted from the decrease to SEC prices of $15.45 to $78.22 per Bbl WTI for crude oil and $3.72 to $2.64 per MMBtu HH for natural gas, (ii) 11.0 MMBoe from non-producing wells that have been plugged and abandoned or are planned to be plugged and abandoned, (iii) negative revisions of 14.2 MMBoe in updates to costs associated with production, and (iv) 0.9 MMBoe in updates to well performance. Negative revisions were partially offset by 9.2 MMBoe from increases in working interests and positive volume changes in natural gas shrinks and NGL yields.

Proved Undeveloped Reserves

	Net Reserves (MBoe)
Beginning of year	71,115
Converted to proved developed	(48,172)
Acquisition of reserves	110,238
Additions from capital program	17,191
Removed from capital program	(4,758)
Revisions to previous estimates	10,946
End of year	156,560

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 our approved development plans. During 2023, we converted 68% of our proved undeveloped reserves, which is comprised of 114 gross wells representing net reserves of 48.2 MMBoe, at a cost of $407.7 million. The 110.2 MMBoe of acquisition of reserves is primarily due to the Hibernia Acquisition and the Tap Rock Acquisition. During the year, we added 48 gross proved undeveloped locations for a total reserve addition of 17.2 MMBoe. Increases in expected performance offset a decrease in SEC pricing year-over-year resulting in an overall positive revision of 10.9 MMBoe.

Proved Reserves Sensitivity Analysis

If crude oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 3% and our PV-10 value as of December 31, 2023 would decrease by approximately 18% or $1.6 billion. If crude oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 2% and our PV-10 value as of December 31, 2023 would increase by approximately 18% or $1.7 billion.

Preparation of Reserves Estimates

Our proved reserves estimates as of December 31, 2023, 2022, and 2021 were based on evaluations prepared by our independent petroleum engineering consulting firm, Ryder Scott Company, L.P. ("Ryder Scott"). Ryder Scott is engaged by and has direct access to the Audit Committee. 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.

In determining our proved reserves estimates, we and Ryder Scott used a combination of performance methods, including decline curve analysis and other computational methods, offset analogies, and seismic data and interpretation. All of our proved undeveloped reserves conform to the SEC's five-year rule requirement as all proved undeveloped locations are scheduled, according to an adopted development plan, to be drilled within five years of the location's initial booking date.

Controls Over Reserve Report Preparation. Inputs and major assumptions related to our proved reserves are reviewed annually by an internal team composed of reservoir engineers, geologists, land, and management for adherence to SEC rules and regulation through a detailed review of land and accounting records, available geological and reservoir data, and production performance data. The internal team compiles the reviewed data and forwards the applicable data to Ryder Scott.

When preparing our reserve estimates, Ryder Scott does not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, sales volumes, well test data, historical costs of operations and development, product prices, or any agreements relating to current and future operations of properties or sales of production. Ryder Scott prepares estimates of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to ensure that the reserve estimates are complete, determined pursuant to acceptable industry methods, and with a level of detail we deem appropriate.

Annually, these reserve estimates are reviewed by our responsible technical person who oversees the 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. After final approval from the responsible technical person, the results are presented to senior management and to our Board for their review. Together, these internal controls are designed to promote a comprehensive, objective, and accurate reserves estimation process.

Qualifications of Responsible Technical Person

Our technical person who was primarily responsible for overseeing the preparation of our reserve estimates is our Director, Corporate Reserves, who has over 35 years of experience in the oil and gas industry, including seven years in her role at Civitas. Her professional qualifications include a bachelor's degree in Mathematics and Computer Science from the Colorado School of Mines.

Qualifications of 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 is set forth in the Ryder Scott reserves report filed as Exhibit 99.1 to this report. 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, Average Sales Prices, and Production Costs

Crude oil and natural gas prices have a significant impact on our earnings and Free Cash Flow. Crude oil and natural gas prices are impacted by various macro-economic factors influencing the balance of supply and demand. These factors include, but are not limited to: production levels, inventory levels, real or perceived geopolitical risks in producing regions, the relative strength of the U.S. dollar, weather, and global demand. These factors are beyond our control and are difficult to predict. We reevaluate our development plan based on crude oil and natural gas prices, however, our strategy is focused on maximizing Free Cash Flow, while maintaining broadly flat production.

The following tables set forth information regarding crude oil, natural gas, and NGL 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.*"

	Sales Volumes			
Year Ended December 31,	**Crude Oil (MBbls)**	**Natural Gas (MMcf)**	**NGL (MMBbls)**	**Total (MBoe)**
2023				
DJ Basin	28,925	110,339	14,199	61,514
Permian Basin	7,801	23,482	4,201	15,916
Total	36,726	133,821	18,400	77,430
2022				
DJ Basin	27,651	112,478	15,666	62,063
2021				
DJ Basin	9,385	36,763	4,934	20,445

	Average Sales Price (1)			
Year Ended December 31,	**Crude Oil (Per Bbl)(2)**	**Natural Gas (Per Mcf)(3)**	**NGL (Per Bbl)**	**Production Cost (Per Boe)(4)**
2023				
DJ Basin	$ 74.01	$ 2.54	$ 23.01	$ 3.93
Permian Basin	$ 81.37	$ 1.07	$ 15.75	$ 6.59
Total	$ 75.57	$ 2.28	$ 21.35	$ 4.47
2022				
DJ Basin	$ 91.70	$ 6.15	$ 35.76	$ 3.25
2021				
DJ Basin	$ 65.41	$ 3.84	$ 34.68	$ 3.41

(1) Excludes the impact of commodity derivatives.
(2) Crude oil sales in the DJ Basin exclude $1.3 million, $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, 2023, 2022, and 2021, respectively.
(3) Natural gas sales in the DJ Basin exclude $4.1 million, $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, 2023, 2022, and 2021, respectively.
(4) Represents lease operating expense and midstream operating expense per Boe using total sales volumes and excludes ad valorem and severance taxes.

Productive Wells

As of December 31, 2023, we had working interests in a total of 5,248 gross productive wells, of which 4,020 were horizontal. Our working and net revenue interest in our productive wells averaged approximately 70% and 57%, respectively. As of December 31, 2023, we operated a total of 4,366 gross productive wells, of which 3,244 were horizontal. Our working and net revenue interest in our operated productive wells averaged approximately 82% and 67%, respectively.

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and crude oil wells awaiting connection to production facilities. Gross wells are the total number of productive wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

The following table sets forth information regarding productive wells by basin as of December 31, 2023:

	Crude Oil		Natural Gas		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
DJ Basin	4,325	2,985	227	204	4,552	3,189	3,825	3,108
Permian Basin	661	474	35	15	696	489	541	472
Total	4,986	3,459	262	219	5,248	3,678	4,366	3,580

Drilling and Completion Activity

The following tables set forth a summary of our operated developmental 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. 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. Wells may be in-process for up to two years.

	Year Ended December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Development wells turned to sales						
DJ Basin	148	124.3	146	129.5	70	61.5
Permian Basin[1]	78	66.0	—	—	—	—
Total	226	190.3	146	129.5	70	61.5
Developmental wells - dry holes						
Permian Basin[1][2]	2	1.7	—	—	—	—

(1) Drilling and completion activity in the Permian Basin represents activity during the period between the closing of the Hibernia Acquisition and the Tap Rock Acquisition on August 2, 2023 and December 31, 2023.

(2) Two in-process developmental wells drilled during Q2 2023, acquired in the Tap Rock Acquisition, were determined to be incapable of producing either crude oil or natural gas in sufficient quantities.

There were no exploratory drilling activities during the years ended December 31, 2023, 2022, and 2021. Additionally, we did not have any dry wells in the DJ Basin during the same periods.

	As of December 31, 2023	
	Gross	Net
In-process development wells		
DJ Basin	92	77.1
Permian Basin[1]	53	42.5
Total	145	119.6

(1) Drilling and completion activity in the Permian Basin represents activity during the period between the closing of the Hibernia Acquisition and the Tap Rock Acquisition on August 2, 2023 and December 31, 2023.

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, 2023. 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	419,800	358,000	177,200	95,600	597,000	453,600
Permian Basin	56,300	43,300	32,200	25,200	88,500	68,500
Other[3]	103,000	41,700	13,200	9,600	116,200	51,300
Total	579,100	443,000	222,600	130,400	801,700	573,400

(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 crude oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) Includes other non-core acreage located in Colorado outside of the DJ Basin, Wyoming, and Montana.

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 19,500 net acres, or 3%, of our 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, 2023, 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 2024		Expiring 2025		Expiring 2026		Expiring 2027 and Beyond	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
DJ Basin	5,400	4,400	9,200	6,800	9,800	3,800	21,000	4,900
Permian Basin	200	200	4,700	2,800	1,400	700	900	700
Other	—	—	—	—	800	800	—	—
Total	5,600	4,600	13,900	9,600	12,000	5,300	21,900	5,600

Title to Properties

Prior to the drilling of a crude oil or natural gas well, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. To the extent title opinions or other investigations reflect title defects impacting the development or operation of a producing property, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the crude oil and natural gas industry. Prior to completing an acquisition of producing crude oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, an updated title review, or review previously obtained title opinions. Our crude oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Derivative Activity

We periodically enter into commodity derivative contracts to mitigate a portion of our exposure to potentially adverse market changes in commodity prices for our expected future crude oil and natural gas production and the associated impact on cash flows. Our commodity derivative contracts consist of swaps, collars, basis protection swaps, and puts. The crude 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, before differentials. Please refer to "*Part II - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations*," "*Part II - Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Derivative Contracts*," and "*Part II - Item 8. Financial Statements and Supplementary Date - Note 9 - Derivatives*" for additional discussion.

Customers

In 2023, we had two customers that represented a combined total of 44% of our revenue; Customer A accounted for 16% of revenue and Customer B accounted for 28% of revenue. We do not believe the loss of any single purchaser would materially impact our operating results, as crude oil, natural gas, and NGL are fungible products with well-established markets and numerous purchasers.

Delivery Commitments

We are party to a number of agreements containing minimum volume commitments that require us to deliver fixed determinable quantities of crude oil, natural gas, and NGL. Under the terms of these agreements, we are required to make periodic deficiency payments for any shortfalls in delivering minimum gross volume commitments. Please refer to "*Part II - Item 8. Financial Statements and Supplementary Date - Note 6 - Commitments and Contingencies*" for additional discussion.

Competition

The crude 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 crude 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 crude oil and natural gas properties, attracting and retaining qualified personnel, and obtaining transportation for the crude oil and natural gas we produce. There is also competition between producers of crude 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 crude 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.

Seasonal Nature of Business

The price of crude oil is primarily driven by global socioeconomic and geopolitical factors and is less affected by seasonal fluctuations; however, demand for energy is generally higher in the winter and in the summer driving season. The demand and price for natural gas generally increases during winter months and decreases during summer months. To lessen the impact of seasonal natural gas demand and price fluctuations, pipelines, utilities, local distribution companies, and industrial users regularly utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can divert natural gas that is traditionally placed into storage which, in turn, may increase the typical winter seasonal price. Seasonal anomalies, such as mild or extreme winters sometimes lessen or exacerbate these fluctuations.

Certain of our drilling, completion, and other operational activities are also subject to seasonal limitations. Seasonal weather conditions, government regulations, and lease stipulations could adversely affect our ability to conduct drilling activities in some of the areas where we operate. Please refer to "*Item 1A. Risk Factors*" of this report for additional discussion.

Insurance Matters

As is common in the crude 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.

Human Capital

As of December 31, 2023, we had 516 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 workers 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 our industry. During 2023, we achieved a TRIR of 0.23.

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 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. We require 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. We provide 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 are committed to ensuring the composition of the Board reflects an overall balance of diversity of experiences, skills, attributes, and viewpoints. Our board consists of 33% women, and 22% are members of a minority group, as defined by the U.S. Equal Employment Opportunity Commission, as of December 31, 2023.

Approximately 23% of our total workforce are women, and 17% are members of a minority group, as of December 31, 2023. As of the same date, 32% of our executives (as defined as persons at the level of Vice President and higher) are women, and 18% are members of a minority group.

Please refer to our Corporate Sustainability Report published on our website for performance highlights regarding various human capital measures and additional sustainability information. Information contained in our Corporate Sustainability Report is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

Offices

As of December 31, 2023, we leased office space in Denver, Colorado at 555 17th Street where our principal offices are located. Additionally, we own and lease various corporate and field office space in Colorado, New Mexico, and Texas.

Regulation of the Crude Oil and Natural Gas Industry

Our operations are substantially affected by federal, state, and local laws and regulations. In particular, crude 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 crude oil and natural gas production have statutory provisions regulating the exploration for and production of crude 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 crude 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 crude 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 states in which we operate, including rules and regulations adopted by 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. In May 2023, COGCC was changed to the Energy & Carbon Management Commission ("ECMC"). These requirements, and any new requirements or potential future rulemakings of the ECMC or other state authorities, could make it more difficult and costly to develop new crude 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 crude 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 many of our properties, as well as Texas and New Mexico, have regulations governing conservation matters, including provisions for the spacing and unitization or pooling of crude 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 crude oil and gas resources. Moreover, the states in which we operate impose a production or severance tax with respect to the production and sale of crude oil, natural gas, and NGL within their jurisdictions.

The states in which we operate also regulate 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. State laws also may 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 crude oil and natural gas 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 crude 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 November 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule sought to 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. In November 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 announced a final rule on December 2, 2023, which, among other things, requires the phase out of routine flaring of natural gas from new oil wells and routine leak monitoring at all well sites and compressor stations. Notably, EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance dates under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, two years to develop and submit their plans for reducing methane from existing sources. The final emissions guidelines under Subpart OOOOc provide three years from the plan submission deadline for existing sources to comply.

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 its existing non-attainment status for the 2008 NAAQS was reclassified from "serious" to "severe" in 2022 due to violations at area monitors during the 2020 ozone season. A "severe" classification triggers 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 in Colorado 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 challenged the EPA's action upon remand in the D.C. Circuit, and the D.C. Circuit denied Weld County's petition for review in June 2023. *Bd. of County Comm. of Weld County v. EPA*, No. 21-1263. While the Permian Basin in Texas and New Mexico has not been designated as being in nonattainment with federal ozone standards, the EPA's 2023 proposal to designate the Permian Basin as being in nonattainment remains pending.

State Air Regulation

The Colorado Department of Public Health and Environment's Air Quality Control Commission ("AQCC") has adopted air quality regulations that impose stringent new requirements to control emissions from both existing and new or modified oil and gas facilities in Colorado, including 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.

These air quality regulations and controls have also been extended for many lower producing and emitting facilities statewide, and storage tank loadout controls added. These rules 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 impose an emission inventory and reporting of GHGs. The AQCC rules specific to the oil and gas sector include emission control requirements for natural gas fired engines typically in compression service and pre-production tanks used in flowback, and a preproduction air monitoring plan requirement for operators.

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. In July 2023, the AQCC adopted a new rule to verify methane emissions from oil and gas production in Colorado as part of the implementation of the greenhouse gas intensity standards it adopted in 2021. The new rule will require oil and gas operators to calculate the intensity of their emissions (tying the level of emissions to the amount of oil and gas produced), directly measure emissions, and regularly report findings to the state. The rule is expected to take effect in 2025.

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. For example, in October 2023, the AQCC adopted the Greenhouse Gas Emissions and Energy Management for Manufacturing Phase 2 rule, which requires 18 of Colorado's highest emitting manufacturers in the industrial sector (which includes energy use in the oil and gas industry) to collectively reduce their GHG levels by 20% by 2030, as compared to 2015 levels. The final rule is expected to take effect in 2024.

In New Mexico, the state legislature is considering a bill that would increase fines and fees on oil and gas operators and codify New Mexico's 98% methane capture rule, which the New Mexico Energy, Minerals and Natural Resources Department enacted in 2021. Under the methane capture rule, oil and gas operators are required to capture 98% of their produced natural gas by December 31, 2026, and routine venting and flaring is prohibited.

Compliance with these and other air pollution control, air monitoring, gas capture, and permitting requirements has the potential to delay the development of crude 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 crude 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 states where we operate have adopted or have considered 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. 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 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 where we operate have adopted their own new requirements on hydraulic fracturing and other oil and gas operations and, in some cases, have proposed initiatives restricting or banning oil and gas development altogether. For example, 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, regulators in the states in which we operate have adopted additional requirements related to seismic safety for hydraulic fracturing activities or the underground injection of fluid wastes. For example, the regulations that the ECMC adopted in November 2020 impose various requirements on the underground injection of fluid wastes to further seismic safety and protect the environment. In Texas, state rules require more frequent reports of injection volume and pressure data in areas of seismicity, and the Texas Railroad Commission can modify, suspend, or terminate an injection permit to dispose of waste for just cause after notice and opportunity for hearing, if injection is likely to be or determined to be contributing to seismic activity. Similarly, in New Mexico, the New Mexico Oil Conservation Division ("OCD") implemented a Seismicity Response Protocol that is implemented either through voluntary actions by operators and/or orders issued by the OCD in response to increased seismic activity believed to be related to injection wells throughout New Mexico. 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 crude 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 and Permian Basin regions.

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 ECMC, as well as other state agencies. Over the past several years, the ECMC 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 ECMC rule violations.

In April 2019, Colorado Senate Bill 19-181 ("SB 181") became effective, which substantially changed the state's regulation of oil and gas exploration and production activities in Colorado.

Among the most significant changes under SB 181 was the 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 ECMC has adopted significant additional regulations to implement SB 181. The legislation mandated ECMC 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 ECMC 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. Additionally, in May 2023, Governor Polis signed Colorado Senate Bill 23-285 (SB23-285) into law, which grants the ECMC the exclusive authority to regulate deep geothermal operations, underground natural gas storage, and carbon capture and storage. Depending on how these and any other new rules are applied and enforced, they could substantially increase in well costs for our Colorado operations, impact our ability to operate and extend the time necessary to obtain drilling permits, which would create substantial uncertainty about future development plans in Colorado.

Our properties located in New Mexico are subject to the authority of the New Mexico Environment Department and the Energy, Minerals and Natural Resources Department's OCD, as well as other state agencies. In December 2023, the New Mexico Environment Department proposed new regulations that would require the reuse of produced water generated by the oil and gas industry, so long as there is no discharge to surface or groundwater.

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 crude oil and natural gas 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 crude 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 2020, the Colorado Department of Public Health & Environment ("CDPHE") proposed new rules governing Technologically Enhanced Naturally Occurring Radioactive Material ("TENORM") waste, which were adopted in November 2020 and became enforceable in July 2022. 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. Regulations in Texas and New Mexico also govern the disposal of NORM generated in connection with oil and gas exploration and production activities. 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 crude 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 order to implement the program, the Inflation Reduction Act required revisions to GHG reporting regulations for petroleum and natural gas systems (Subpart W) by 2024. In July 2023, the EPA proposed to expand the scope of the Greenhouse Gas Reporting Program for petroleum and natural gas facilities, as required by the Inflation Reduction Act. Among other things, the proposed rule expands the emissions events that are subject to reporting requirements to include "other large release events" and applies reporting requirements to certain new sources and sectors. The rule is currently scheduled to be finalized in the spring of 2024 and would take effect on January 1, 2025, in advance of the deadline for GHG reporting for 2024 (March 2025). The fee imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 would be $900 per ton emitted over annual methane emissions thresholds, and will increase to $1,200 in 2025, and $1,500 in 2026. 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, the development of greenhouse gas inventories, 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 2021, as a party to the Paris Agreement, the U.S. announced 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. At the 27th Conference of Parties ("COP27"), President Biden 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. Most recently, at the 28th Conference of the Parties ("COP28"), President Biden announced the EPA's final standards to reduce methane emissions from existing oil and gas sources. Additionally, at COP28, member countries entered into an agreement that calls for actions towards achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement, among other things, is to accelerate efforts towards the phase-down of unabated coal power, phase out inefficient fossil fuel subsidies, and take other measures that drive the transition away from fossil fuels in energy systems. 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 state’s 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. In October 2023, the AQCC adopted the Greenhouse Gas Emissions and Energy Management for Manufacturing Phase 2 rule, which requires 18 of Colorado’s highest emitting manufacturers in the industrial sector (which includes energy use in the oil and gas industry) to collectively reduce their GHG levels by 20% by 2030, as compared to 2015 levels. The final rule is expected to take effect in 2024.

In New Mexico, the state legislature is considering a bill that would increase fines and fees on oil and gas operators and codify New Mexico’s 98% methane capture rule, which the New Mexico Energy, Minerals and Natural Resources Department enacted in 2021. Under the methane capture rule, oil and gas operators are required to capture 98% of their produced natural gas by December 31, 2026, and routine venting and flaring is prohibited.

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 crude 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 definition of WOTUS was further impacted by the U.S. Supreme Court’s decision issued in May 2023 in Sackett v. EPA, wherein the Court held that the jurisdiction of CWA extends only to those adjacent wetlands that are indistinguishable from traditional navigable bodies of water due to a continuous surface connection and rejected the “significant nexus” test embraced in earlier jurisprudence. In September 2023, EPA and the Corps published a direct-to- final rule redefining WOTUS to amend the January 2023 rule and align with the decision in Sackett. The final rule eliminated the “significant nexus” test from consideration when determining federal jurisdiction and clarified that the CWA only extends to relatively permanent bodies of water and wetlands that have a continuous surface connection with such bodies of water.

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.

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. In January 2021, the Department of the Interior finalized a rule limiting application of the MBTA; however, the Department of the Interior revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental taking under certain prescribed conditions. In June 2023, the U.S. Fish and Wildlife Service issued three proposed rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. The comment periods for these rules ended in August 2023, and final rules are expected by April 2024. 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. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us or our customers to incur costs or take other measures which may adversely impact our business or operations.

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

Crude oil and natural 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 crude oil and natural gas projects on federal lands. Authorizations under NEPA also are subject to protest, appeal, or litigation, which can delay or halt projects. In July 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 in April 2022, and generally restored provisions that were in effect prior to 2020. In July 2023, CEQ issued a proposed rule for the Phase II rulemaking. The proposed Phase II rule restores certain mitigation language from the pre-2020 version of the NEPA regulations, proposes further revisions to ensure the NEPA process "provides for efficient and effective environmental reviews," and meets environmental, environmental justice, and climate change objectives. A final rule is expected in April 2024. 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.

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.

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.

We have also posted to our website our Audit Committee Charter, Compensation Committee Charter, Nominating and Corporate Governance Committee Charter, ESG Committee Charter, Corporate Governance Guidelines, Code of Business Conduct and Ethics, and Insider Trading Policy, in addition to all pertinent company contact information.

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 crude 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 crude oil, natural gas, and NGL 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 crude oil and natural gas reserves or anticipated sales volumes.
- Drilling for and producing crude 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.
- We intend to pursue the further development of our properties through horizontal drilling and completion, which can be more operationally challenging and costly relative to vertical drilling operations.
- Several of our recent acquisitions represent an expansion outside of the DJ Basin, and we may encounter new obstacles operating in different geographic regions.
- 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.
- We face increasing risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in the states in which we operate, particularly in Colorado.
- 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 crude 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 crude 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 crude 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 crude 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.
- Certain past transactions triggered a limitation on the utilization of our historic U.S. net operating loss carryforwards (“NOLs”) and the NOLs acquired in such transactions.
- 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 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.
- CPPIB Crestone Peak Resources Canada Inc., a Canadian corporation (the “Crestone Peak Stockholder”) is a significant holder of our common stock and may have some ability to influence our management and affairs.
- 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 crude 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 crude oil, natural gas, and NGL 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. Crude 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 crude oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, crude oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because approximately 68% of our estimated proved reserves as of December 31, 2023 were crude oil and NGL, our financial results are more sensitive to movements in crude oil and NGL prices.

During times of suppressed crude 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 crude oil, natural gas, and NGL 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, 2023, the daily NYMEX WTI crude oil spot price ranged from a high of $93.67 per Bbl to a low of $66.61 per Bbl, and the NYMEX HH natural gas spot price ranged from a high of $3.78 per MMBtu to a low of $1.74 per MMBtu. As of February 23, 2024, the daily NYMEX WTI crude oil spot price and NYMEX HH natural gas spot price was $76.49 per Bbl and $1.60 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 crude oil and natural gas;
- the actions from members of the Organization of Petroleum Exporting Countries and other crude oil producing nations;
- the price and quantity of imports of foreign crude oil and natural gas;
- political conditions in or affecting other crude oil and natural gas producing countries, including the current conflicts in the Middle East (including the current events related to the Israel-Palestine conflict) and involving Russia and Ukraine and conditions in South America;
- the level of domestic and global crude oil and natural gas exploration and production;
- the level of domestic and global crude 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 crude oil and the speculative trading of crude oil and natural gas futures contracts;
- the price and availability of competitors' supplies of crude 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 NGL 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 crude 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 crude oil and natural gas 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 crude oil, natural gas, and NGL and will be affected by continuing and prolonged declines in such prices.

Crude oil, natural gas, and NGL prices are volatile. It is common within the industry to hedge a portion of crude 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. 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. As of December 31, 2023, we have hedged approximately 45,000 Bbls of crude oil per day in 2024, but our hedging for 2025 crude oil production is far 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 “*Part II - Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives*” 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 crude oil and natural gas, we have, and may in the future enter into additional, derivative arrangements for a portion of our crude 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 crude 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 indentures 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.

On August 2, 2023, in connection with the closing of several of our recent acquisitions, the Credit Facility was amended to increase the borrowing base to $3.0 billion, with an aggregate maximum credit commitment of $4.0 billion and aggregate elected commitments of $1.85 billion. The next scheduled borrowing base redetermination date is set to occur in May 2024.

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 crude oil and natural gas reserves or anticipated sales 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 crude 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 crude oil and natural gas we are able to produce from new and existing wells;
- the prices at which our crude oil and natural gas are sold;
- the costs of developing and producing our crude 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 crude 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 crude oil and natural gas reserves, and an adverse effect on our business, financial condition, and results of operations.

Drilling for and producing crude 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 crude 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 crude 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 crude 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 crude 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 crude 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 "*Item 1. Business - Estimated Proved Reserves*" 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, 2023, 2022, and 2021.

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 crude 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 crude 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, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable crude 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 crude 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 crude 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 crude oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2023, 2022, and 2021, 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 crude oil and natural gas properties will be affected by factors such as:

- actual prices we receive for crude 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 crude 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 crude 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 crude 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 crude 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 crude oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. Given the historical price volatility in the crude 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 crude 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.

We intend to pursue the further development of our properties through horizontal drilling and completion, which can be more operationally challenging and costly relative to 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 crude oil and natural gas 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.

Several of our recent acquisitions represent an expansion outside of the DJ Basin, and we may encounter new obstacles operating in different geographic regions.

Our operations have historically focused on a single geographic region, namely the DJ Basin in the Rocky Mountain Region. Several of our recent acquisitions represent an expansion into the Permian Basin in Texas and New Mexico, which is our first expansion of our operations outside of the DJ Basin. Certain aspects related to operating in the Permian Basin may not be as familiar to us as our DJ Basin project areas. As a result, we may encounter obstacles that may cause us not to achieve the expected results of such acquisitions and subsequent acquisitions. These obstacles may include a less familiar geological landscape, different completion techniques, midstream and downstream operators with whom we have no established relationship, greater competition for acreage, unfamiliar operating conditions, and a distinct regulatory environment. Additionally, the character of newly acquired assets may be substantially different in operating or geological characteristics or geographic location than our existing properties. Any adverse conditions, regulations or developments related to our expansion into the Permian Basin, or other new geographic regions may have a negative impact on our business, financial condition, and results of operations.

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 crude 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.

We face increasing risk associated with the long-term trend toward increased activism against oil and gas exploration and development activities in the states in which we operate, particularly in Colorado.

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 state regulators;
- 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.

Among the most significant changes under the legislation was the 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 is 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.

Permitting delays that result from the new ECMC rules and regulations or other state rules and regulations could substantially curtail our near-term pace of new crude oil and natural gas development. We have observed a decline in the pace at which permit applications are being granted in Colorado, and if this trend continues in any of the states in which we operate, it could have a material adverse effect on our business, financial condition, production targets, and results of operations.

Rules adopted by regulators in the states in which we operate may significantly increase our operating costs and have a material adverse effect on our business, financial condition, and results of operations. See "*Item 1. Business - Regulation of the Crude Oil and Natural Gas Industry*" for more information regarding the new and proposed state environmental regulations applicable to our business.

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 the states in which we conduct our operations. These efforts could have a material adverse effect on our business, financial condition, and results of operations.

SB 181's requirement, which applies to our Colorado operations, 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.

With respect to our operations in the DJ Basin in Colorado, 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.

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 crude 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 22% of our total proved reserves were classified as proved undeveloped as of December 31, 2023. 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; crude 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 crude 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 crude 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 crude 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 crude oil or natural gas will be present or, if present, whether crude 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 crude 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, 2023, approximately 25,100 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 4,600 net acres will expire in 2024, approximately 9,600 net acres will expire in 2025, and approximately 10,900 net acres will expire in 2026 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 crude 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 crude 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 crude 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 crude oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including, but not limited to, the possibility of:

- environmental hazards, such as spills, uncontrollable flows of crude 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 crude oil and natural gas 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 crude 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 states in which we operate have implemented or are considering additional regulations governing 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, wildlife protection, and financial assurance.

Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of crude 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 a significant portion our operations and reserves are 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 crude 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 crude 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 adopted regulations requiring the reporting of GHG emissions from specific categories of higher GHG emitting sources in the U.S., including certain crude 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. In November 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. In November 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 announced a final rule in December 2023, which, among other things, requires the phase out of routine flaring of natural gas from new crude oil wells and routine leak monitoring at all well sites and compressor stations. Notably, EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance dates under state plans. The final rule gives states, along with federal tribes that wish to regulate existing sources, two years to develop and submit their plans for reducing methane from existing sources. The final emissions guidelines under Subpart OOOOc provide three years from the plan submission deadline for existing sources to comply. 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. A final rule is anticipated in 2024. 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 crude 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 crude 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, wildfires, storms, floods, and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the crude 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 more stringent air emissions regulations and 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 our 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 crude 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 crude 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, our 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 our business strategy.

Furthermore, the crude 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 crude 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. 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. There is also a risk that financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector, and 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 our 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 our operations and could have an adverse impact on our 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 our 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 contained in "*Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the crude 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, our 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. Further, failure or a perception (whether or not valid) of failure to implement our ESG strategy or achieve sustainability goals and targets we have set, including emissions reduction goals, could damage our reputation, causing our investors or consumers to lose confidence in our Company and negatively impact our operations. Our continuing efforts to research, establish, accomplish and accurately report on the implementation of our ESG strategy, including any ESG goals, may also create additional operational risks and expenses and expose us to reputational, legal and other risks. For example, growing interest on the part of investors and regulators in ESG factors and increased demand for, and scrutiny of, ESG-related disclosure by stakeholders has also increased the risk that companies could be perceived as, or accused of, making inaccurate or misleading statements regarding their ESG-related claims, goal, targets, efforts or initiatives, often referred to as "greenwashing." Such perception or accusation could damage our reputation and result in litigation or regulatory actions. 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 stockholders, 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 totaling $247.2 million at December 31, 2023, and the sale of our crude oil, natural gas, and NGL totaling $506.0 million in receivables at December 31, 2023, 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 crude oil, natural gas, and NGL 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 any of our counterparties, 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 crude 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 crude 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 the states we operate in, 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 ad valorem and severance tax laws in the states we operate in 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.

Certain past transactions triggered a limitation on the utilization of our historic U.S. NOLs and the NOLs acquired in such transactions.

Our ability to utilize NOLs (including NOLs acquired in certain prior transactions) to reduce future taxable income following such transactions depends on many factors, including our future income, which cannot be assured. Section 382 of the Internal Revenue 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. We believe that ownership changes occurred as a result of the aforementioned transactions with respect to us and the entities involved in such transactions, which triggered a limitation (calculated as described above) on our ability to utilize any historic NOLs following such transactions. In addition, the NOLs from one of the companies acquired in such transactions are further limited under Section 382 of the Internal Revenue Code as a result of a prior ownership change that occurred.

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 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 2023 calendar year, the closing sales price of our common stock ranged from a low of $54.58 per share to a high of $85.24 per share. The trading price of our common stock may be affected by a number of factors, including the volatility of crude 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 crude 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 crude oil, natural gas, and NGL prices could have a material adverse effect on the 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 indentures 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 indentures 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 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 such stockholder became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board.

The Crestone Peak Stockholder is a significant holder of our common stock and may have some ability to influence our management and affairs.

As of the date hereof, the Crestone Peak Stockholder owns approximately 18% of our outstanding common stock, representing approximately 18% of our combined voting power. As a result, we believe that 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 Crestone Peak Stockholder continues to be the owner of a significant amount of our common stock, the prospect that it may be able to influence matters requiring stockholder approval may continue. In any of these matters, the interests of the Crestone Peak Stockholder and of our other stockholders may differ or conflict. Moreover, in the event that the Crestone Peak Stockholder continues 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 1C. *Cybersecurity.*

We consider cybersecurity risk to be an important potential risk to our business. Our Audit Committee maintains oversight of cybersecurity and other information technology risks affecting us. As such, on a quarterly basis, or as frequently as required, management provides reports regarding cybersecurity and other information technology risks to the Audit Committee, which, pursuant to its charter, is generally responsible for the oversight of many of our broader risk assessment and risk management policies. These management updates are designed to inform the Audit Committee of any potential risks relating to information security or data privacy and may outline any relevant mitigation or remediation tactics being implemented.

Our Vice President of Information Technology, Jerry Vigil, leads our cybersecurity initiatives, reporting directly to the Chief Administrative Officer and Corporate Secretary and maintains open communication channels with the broader senior management team, the Board, and our Audit Committee. Mr. Vigil is responsible for implementing our cybersecurity strategy, managing daily operations, coordinating incident response, and regularly and routinely reviewing our security model and its practices and future initiatives with external auditors to ensure alignment with industry best practices, changes in audit compliance requirements, and adherence to planned business objectives, as well as providing regular updates and reports on our cybersecurity status and risk assessments to the Board. Mr. Vigil has over 25 years of information technology management experience and has served as our Vice President of Information Technology since January 2024. Mr. Vigil served in the same role at HighPoint Resources Corporation from May 2014 until its merger with us in April 2021. Mr. Vigil served as our Director of Information Technology from April 2021 through December 2023. Mr. Vigil has a Bachelor of Science in Business Technology Management and Computer Science from Regis University.

We maintain a robust system of data protection and cybersecurity resources, technology and processes. We regularly evaluate new and emerging risks and ever-changing legal and compliance requirements. We make strategic investments to address these risks and compliance requirements to keep our data secure. We monitor risks of sensitive information and reevaluate these risks on a frequent basis. We also perform annual and ongoing cybersecurity awareness training for our employees. We have a longstanding information security risk program structured according to the National Institute of Standards and Technology Cybersecurity Framework, industry best practices, privacy legislation, and other global and local standards and regulations. This program deploys both commercially available solutions and proprietary systems to manage threats to our information technology environment actively and includes a defense-in-depth approach with multiple layers of security controls, including network segmentation, security monitoring, endpoint protection, and identity and access management, as well as data protection best practices and data loss prevention controls, all of which are intended to preserve the confidentiality, integrity, and continued availability of all information owned by, or in the care of, us.

We also employ a cybersecurity awareness program, which incorporates external expertise and guidance in all aspects of our cybersecurity program, that includes an extensive onboarding training requirement and monthly ongoing training on protecting corporate data and digital assets. We complete annual internal security audits and vulnerability assessments of our information systems and related controls, including systems affecting personal data. In addition, we leverage cybersecurity specialists to complete annual external audits and objective assessments of our cybersecurity program and practices, including our data protection practices, as well as to conduct targeted attack simulations. We continually enhance our information security capabilities in order to protect against emerging threats, while also increasing our ability to detect and respond to cyber incidents and maximize our resilience to recover from potential cyber-attacks. We have a robust incident response plan in place that provides a documented runbook for responding to cybersecurity incidents and facilitates coordination across multiple parts of our entity. Additionally, we have purchased network security and cyber liability insurance in order to provide a level of financial protection, should a data breach occur. Our insurance covers situations arising from, among other things, cyber-related breaches and interruptions in the business continuity of our computing environment. These policies are annually reviewed by industry underwriters at which time our security practices, programs, processes, and procedures are thoroughly disclosed, reviewed, and evaluated for purposes of determining our insurability.

We have not experienced any material information security breaches in the last three years, nor are we aware of any cybersecurity risks that are reasonably likely to have a material adverse affect on us. As such, we have not spent any material amount of capital on addressing information security breaches in the last three years, nor have we incurred any material expenses from penalties and settlements related to a material breach during this same time. For additional information about our cybersecurity risks, please refer to "*Item 1A. Risk Factors - We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption, or financial loss*.".

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.***

We are a party to various routine legal proceedings, disputes and claims arising in the ordinary course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the crude oil and natural gas exploration and development industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to crude oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, results of operations or cash flows. For additional information regarding legal proceedings and environmental matters, refer to "*Part II, Item 8. Financial Statements and Supplementary Data - Note 6 - Commitments and Contingencies*."

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 we believe could exceed $0.3 million. We have received Notices of Alleged Violations ("NOAV") from the ECMC alleging violations of various Colorado statutes and ECMC regulations governing oil and gas operations. We have further received notices from the Colorado Air Pollution Control Division. We continue to engage in discussions regarding resolution of the alleged violations and we anticipate the assessed penalties to be approximately $0.6 million.

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 23, 2024, there were approximately 143 registered holders of our common stock.

Dividend Policy. As approved by the Board, cash dividends are paid quarterly and consist of a base and variable component. Variable cash dividends are 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.

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. Financial Statements and Supplementary Data - Note 5 - Long-Term Debt*" of this report.

Issuer Purchases of Equity Securities. The following table provides information about our purchases of our common stock during the three months ended December 31, 2023.

	Total Number of Shares Purchased[2]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	Maximum Dollar value that May Yet be Purchased Plans or Programs (in thousands)[1]
October 1, 2023 - October 31, 2023	912	$ 79.11	—	$ 479,810
November 1, 2023 - November 30, 2023	366	$ 69.03	—	479,810
December 1, 2023 - December 31, 2023	87	$ 69.29	—	479,810
Total	1,365	$ 75.78	—	$ 479,810

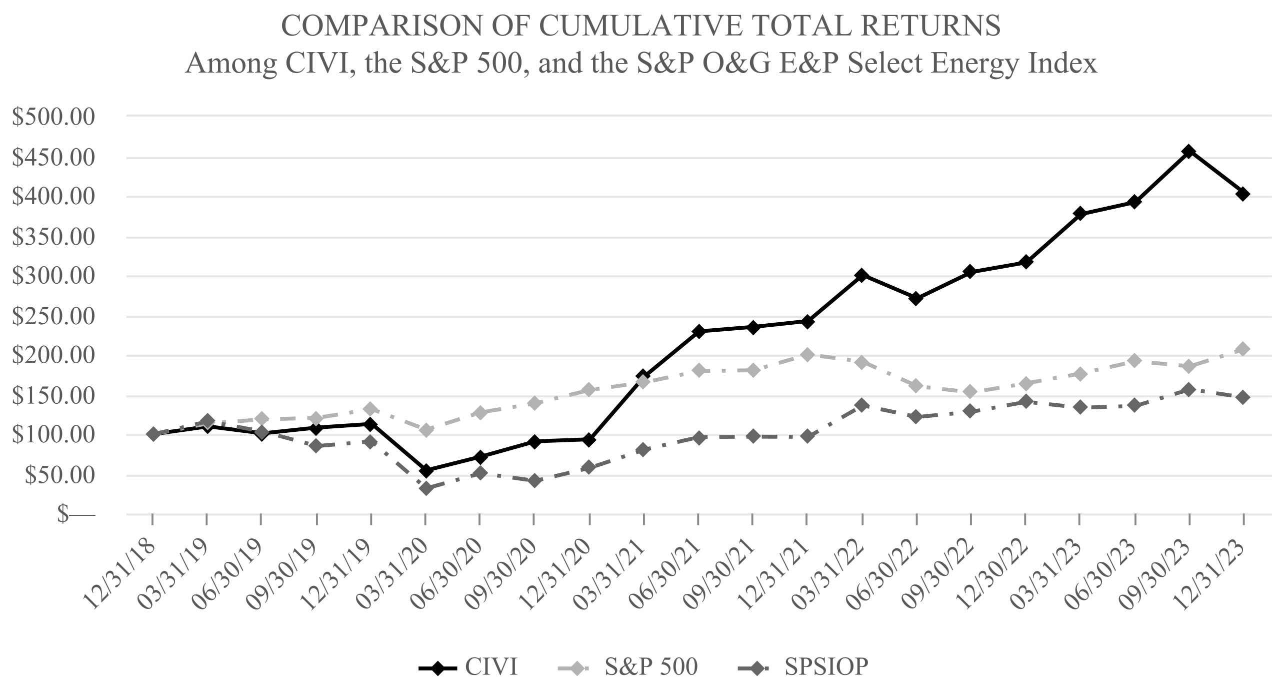
(1) In February 2023, we announced that the Board provided authorization for the stock repurchase program pursuant to which we may, from time to time and through December 31, 2024, acquire shares of our common stock in the open market, in privately negotiated transactions, or through block trades, derivative transactions, or purchases made in accordance with the Rule 10b5-1 of the Exchange Act in an amount not to exceed $1.0 billion, exclusive of any fees, commissions, or other expenses related to such repurchases. In June 2023, commensurate with the announcement of the Hibernia Acquisition and Tap Rock Acquisition, the Board reduced the amount of stock authorized for repurchase by us under the stock repurchase program from $1.0 billion to $500.0 million. The stock repurchase program does not require any specific number of shares to be acquired and can be modified or discontinued by the Board at any time.

(2) Purchases outside of our stock repurchase program represent shares withheld from officers, former officers, executives, and employees for the payment of personal income tax withholding obligations upon the vesting of restricted stock awards. The withheld shares are not considered common stock repurchased under the stock repurchase program.

Sale of Unregistered Securities. Other than as previously reported on our Current Reports on Form 8-K, filed with the SEC on June 20, 2023 and August 2, 2023, we had no sales of unregistered securities during the year ended December 31, 2023.

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 our 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, 2018 through December 31, 2023. The graph assumes that $100 was invested on December 31, 2018 in our common stock, 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. Additionally, due to the combination of different units of volumetric measure, the number of decimal places presented and rounding, certain results may not calculate explicitly from the values presented in the tables.

This section of this Form 10-K generally discusses 2023 and 2022 results and year-to-year comparisons between 2023 and 2022. Discussions of 2021 items and year-to-year comparisons between 2022 and 2021 that are not included in this Form 10-K can be found in "*Part II - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*" of our Annual Report on Form 10-K for the fiscal year ended December 31, 2022.

Executive Summary

We are an independent exploration and production company focused on the acquisition, development, and production of crude oil and associated liquids-rich natural gas primarily in the DJ Basin in Colorado and the Permian Basin in Texas and New Mexico. Our primary objective is to maximize stockholder returns by responsibly developing our crude oil and natural gas resources. To achieve this, we are 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 cash to stockholders, and demonstrate ESG leadership.

2023 Financial and Operating Results

Our financial and operational results for the year ended December 31, 2023:

- Total sales volumes increased 25% when compared to 2022 and average sales volumes per day increased to 273 MBoe/d(1) compared to 170 MBoe/d during 2022, in each case, primarily as a result of the Hibernia Acquisition and the Tap Rock Acquisition;
- Cash dividends declared of $668.7 million, or $7.60 per share;
- Repurchased 5.2 million shares of our common stock at a weighted average price of $61.21 per share;
- Net income of $784.3 million, or $9.02 per diluted share;
- Cash flows provided by operating activities were $2.2 billion compared to $2.5 billion during 2022. Free Cash Flow(2) was $795.9 million compared to $1.2 billion during 2022; and
- Proved reserves increased by 68% to 697.8 MMBoe when compared to 2022, primarily as a result of the Hibernia Acquisition and the Tap Rock Acquisition.

(1) Average sales volumes per day for the Permian Basin is calculated based on the number of days between the closing of the Hibernia Acquisition and the Tap Rock Acquisition on August 2, 2023 and December 31, 2023

(2) Free Cash Flow is a non-GAAP financial measure. Please refer to the "*Reconciliation of Free Cash Flow to Cash Provided by Operating Activities*" and "*Liquidity and Capital Resources*" for additional discussion.

2023 Transactions and Operations

On August 2, 2023, we closed on the Hibernia Acquisition and the Tap Rock Acquisition. The Hibernia Acquisition included approximately 38,000 net acres in the Midland Basin and certain related oil and gas assets in exchange for aggregate consideration of approximately $2.2 billion in cash, inclusive of customary post-closing adjustments. The Tap Rock Acquisition included approximately 30,000 net acres in the Delaware Basin and certain related oil and gas assets in exchange for aggregate consideration of approximately $1.5 billion in cash and 13.5 million shares of our common stock, inclusive of customary post-close adjustments. Furthermore, on October 3, 2023, we entered into a purchase and sale agreement with Vencer Energy, LLC to acquire certain oil and gas properties, interests and related assets (the "Vencer Acquisition"), which closed on January 2, 2024. The Vencer Acquisition included approximately 44,000 net acres in the Midland Basin in exchange for aggregate consideration of approximately $1.0 billion in cash and 7.3 million shares of our common stock paid at the closing of the Vencer Acquisition and $550.0 million in cash to be paid on or before January 3, 2025. The cash portion of the acquisitions were funded by cash on hand and the issuance of three separate Senior Notes for an aggregate principal amount of $3.7 billion. Please refer to "*Item 8. Financial Statements and Supplementary Data - Note 2 - Acquisitions and Divestitures*" and "*Item 8. Financial Statements and Supplementary Data - Note 5 - Long-Term Debt*" for additional discussion.

During 2023, our total capital expenditures in drilling, completions, land, and midstream assets were $1.4 billion. In the DJ Basin, we operated approximately 2.0 drilling rigs and 1.8 completion crews, allowing us to drill 107 gross (90.6 net) operated wells and turn to sales 148 gross (124.3 net) operated wells. Subsequent to the acquisition of the Permian assets in August 2023, we operated approximately 5.6 drilling rigs, and 2.7 completion crews, allowing us to drill 55 gross (44.4 net) operated wells and turn to sales 78 gross (66.0 net) operated wells in the Permian Basin.

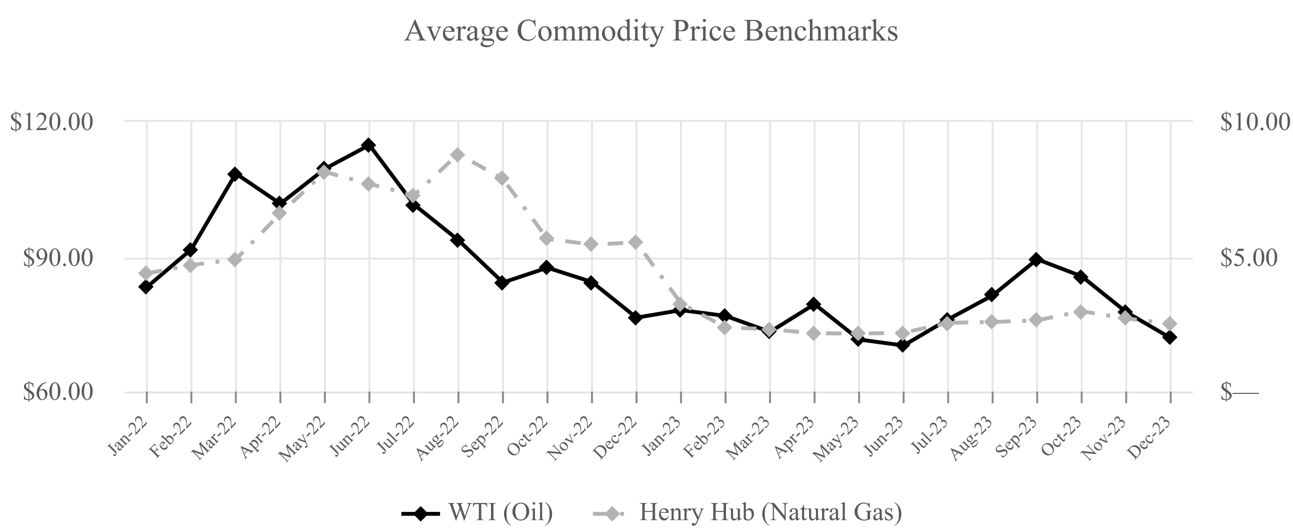
In addition to our continued growth in operations, we have advanced in our ESG initiatives including certain initiatives designed to help us meet our overall GHG emissions reduction goals. Within our capital program, we completed certain retrofit programs and regulation compliance. Other capital spend was used towards the purchase of carbon credits and renewable energy credits. Our spending associated with compliance and GHG emission reduction goals has not had a material impact on our business, financial condition, or results of operations.

Commodity Prices and Certain Other Market Conditions

The crude oil and natural gas industry is cyclical and commodity prices are inherently volatile. Commodity prices continue to be impacted by various macro-economic factors influencing the balance of supply and demand. In 2023, commodity pricing decreased when compared to 2022 due to the net impact of higher supply and accumulation of global oil inventories, recession concerns, instability in the banking industry, and uncertainties around political conditions in or affecting other crude oil and natural gas producing countries, including Israel-Palestine conflicts, the Russia and Ukraine war and conditions in South America. OPEC+ continued to proactively adjust its production to attempt stabilizing the global oil markets and announced production cuts that remained in place through 2023.

Inflation rates in 2023 fell when compared to 2022, however, they are still higher than historical averages. Inflationary pressures can create economic slowdown and/or lead to a recession. A slowdown or recession can cause a decrease in short-term or longer-term demand for commodities, resulting in oversupply and potential for lower commodity prices. Lower prices and inflationary costs could impact our drilling program. The foregoing destabilizing factors have caused dramatic fluctuations in global financial markets and uncertainty about world-wide crude oil and natural gas supply and demand, which in turn has increased the volatility of crude oil and natural gas prices.

The below graph depicts month average NYMEX WTI crude oil and NYMEX natural gas HH spot price over the years ended December 31, 2023 and December 31, 2022.



(1) The average NYMEX WTI crude oil spot price for the years ended December 31, 2023 and 2022 was $77.58 and $94.90, respectively.
(2) The average NYMEX natural gas HH spot price for the years ended December 31, 2023 and 2022 was $2.53 and $6.45, respectively.

In light of uncertainty associated with crude 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 crude oil and natural gas. We periodically enter into derivative contracts for crude oil, natural gas, and NGL using NYMEX futures or over-the-counter derivative financial instruments.

We receive a premium or discount to the benchmark WTI price for our crude oil production. The differential between the benchmark price and the price we receive can reflect adjustments for quality, location, and transportation. Our DJ Basin crude oil price includes a higher-grade quality differential and a transportation differential for delivery to Cushing, Oklahoma. Our Permian Basin crude oil price includes a basis differential between Cushing and Midland, Texas referred to as the Mid-Cush differential. For 2023, this differential primarily sold at premium, however, basis differentials can be volatile and can change at various times. They highly correlate with market dynamics, supply and demand, and overall production.

Our natural gas production is typically sold at a discount to the benchmark NYMEX Henry Hub price. Our DJ Basin natural gas production is sold based on prices established for Colorado Interstate Gas (CIG) and our Permian Basin natural gas production is based on the Waha Hub in West Texas. Pricing we receive for our natural gas in both basins is correlated with the capacity of in-field gathering systems, compression, and processing facilities, as well as transportation pipelines out of the basins, of which are majority owned and operated by third parties. We periodically enter into natural gas basis protection swaps to mitigate a portion of our exposure to adverse market changes.

Outlook

Our 2024 capital investments in drilling, completions, land, and midstream, which we expect to be between $1.8 billion to $2.1 billion, are focused on the continued execution of our development plans in the DJ Basin and Permian Basin. We have operational flexibility to control the pace of our capital spending and we regularly monitor external factors that may negatively impact it. We may revise our capital program during the year as a result of this.

Our 2024 capital program allocates approximately 60% to the Permian Basin, which includes drilling and completing 130 to 150 gross operated wells. Capital investments in the DJ Basin for 2024 are expected to be approximately 40% of our total capital program, which includes drilling and completing 90 to 110 gross operated wells. We continue to incorporate capital spend from our budget towards emission reduction projects, compliance with regulations, and the purchase of carbon credits and renewable energy credits. We do not presently anticipate the occurrence of any material effects on our business, financial condition, or results of operations in future periods as a result of capital designated on these initiatives.

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, 2023	Year Ended December 31, 2022	Change	Percent Change
Revenues (in thousands):				
Crude oil sales[1]	$ 2,775,364	$ 2,535,496	$ 239,868	9 %
Natural gas sales[2]	305,629	691,903	(386,274)	(56)%
NGL sales	392,828	560,185	(167,357)	(30)%
Product revenue	$ 3,473,821	$ 3,787,584	$ (313,763)	(8)%
Sales Volumes:				
Crude oil (MBbls)	36,726	27,651	9,075	33 %
Natural gas (MMcf)	133,821	112,478	21,343	19 %
NGL (MBbls)	18,400	15,666	2,734	17 %
Total sales volumes (MBoe)	77,430	62,063	15,367	25 %
Average Sales Prices (before derivatives):				
Crude oil (per Bbl)	$ 75.57	$ 91.70	$ (16.13)	(18)%
Natural gas (per Mcf)	2.28	6.15	(3.87)	(63)%
NGL (per Bbl)	21.35	35.76	(14.41)	(40)%
Total (per Boe)	44.86	61.03	(16.17)	(26)%
Average Sales Prices (after derivatives)[3]:				
Crude oil (per Bbl)	$ 73.95	$ 79.17	$ (5.22)	(7)%
Natural gas (per Mcf)	2.22	4.47	(2.25)	(50)%
NGL (per Bbl)	21.35	33.14	(11.79)	(36)%
Total (per Boe)[3]	43.98	51.73	(7.75)	(15)%

(1) Crude oil sales excludes $1.3 million and $0.6 million of crude oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2023 and 2022, respectively.

(2) Natural gas sales excludes $4.1 million and $3.2 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2023 and 2022, respectively.

(3) Average sale prices, after derivatives is a non-GAAP financial measure. For a reconciliation of average sales price, before derivatives to average sales price, after derivatives, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Non-GAAP Financial Measures” of this Form 10-K.

The following table presents crude oil, natural gas, and NGL sales volumes by operating region for the periods presented:

	Year Ended December 31,			Percent Change	
	2023	2022	2021	2023-2022	2022-2021
Crude oil (MBbls)					
DJ Basin	28,925	27,651	9,385	5 %	195 %
Permian Basin	7,801	—	—	100 %	— %
Total	36,726	27,651	9,385	33 %	195 %
Natural gas (MMcf)					
DJ Basin	110,339	112,478	36,763	(2)%	206 %
Permian Basin	23,482	—	—	100 %	— %
Total	133,821	112,478	36,763	19 %	206 %
NGL (MBbls)					
DJ Basin	14,199	15,666	4,934	(9)%	218 %
Permian Basin	4,201	—	—	100 %	— %
Total	18,400	15,666	4,934	17 %	218 %
Total sales volumes (MBoe)					
DJ Basin	61,514	62,063	20,445	(1)%	204 %
Permian Basin	15,916	—	—	100 %	— %
Total	77,430	62,063	20,445	25 %	204 %
Average sales volumes per day (MBoe/d)					
DJ Basin	168	170	56	(1)%	204 %
Permian Basin(1)	105	—	—	100 %	— %
Total	273	170	56	61 %	204 %

(1) Average sales volumes per day for the Permian Basin is calculated based on the number of days between the closing of the Hibernia Acquisition and the Tap Rock Acquisition on August 2, 2023 and December 31, 2023.

Total product revenues decreased by 8% to $3.5 billion for the year ended December 31, 2023 compared to $3.8 billion for the year ended December 31, 2022. The decrease was primarily due to a 26% decrease in total commodity pricing, excluding the impact of derivatives, partially offset by a 25% increase in total sales volumes driven by the assets acquired in the Permian Basin through the Hibernia Acquisition and Tap Rock Acquisition which closed on August 2, 2023.

The following tables set forth information regarding crude oil, natural gas, and NGL sales prices, excluding impact of commodity derivatives and production costs for the periods presented.

	Average Sales Price			
Year Ended December 31,	Crude Oil (Per Bbl)[(1)]	Natural Gas (Per Mcf)[(2)]	NGL (Per Bbl)	Production Cost (Per Boe)[(3)]
2023				
DJ Basin	$ 74.01	$ 2.54	$ 23.01	$ 3.93
Permian Basin	$ 81.37	$ 1.07	$ 15.75	$ 6.59
Total	$ 75.57	$ 2.28	$ 21.35	$ 4.47
2022				
DJ Basin	$ 91.70	$ 6.15	$ 35.76	$ 3.25
2021				
DJ Basin	$ 65.41	$ 3.84	$ 34.68	$ 3.41

(1) Crude oil sales in the DJ Basin exclude $1.3 million, $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, 2023, 2022, and 2021, respectively.
(2) Natural gas sales in the DJ Basin exclude $4.1 million, $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, 2023, 2022, and 2021, respectively.
(3) Represents lease operating expense and midstream operating expense per Boe using total sales volumes and excludes ad valorem and severance taxes.

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

	Year Ended December 31,			
	2023	2022	Change	Percent Change
Operating Expenses:				
Lease operating expense	$ 301,288	$ 169,986	$ 131,302	77 %
Midstream operating expense	45,080	31,944	13,136	41 %
Gathering, transportation, and processing	290,645	287,474	3,171	1 %
Severance and ad valorem taxes	276,535	305,701	(29,166)	(10)%
Exploration	2,178	6,981	(4,803)	(69)%
Depreciation, depletion, and amortization	1,171,192	816,446	354,746	43 %
Abandonment and impairment of unproved properties	—	17,975	(17,975)	(100)%
Transaction costs	84,328	24,683	59,645	242 %
General and administrative expense	161,077	143,477	17,600	12 %
Other operating expense	7,437	2,691	4,746	176 %
Total operating expenses	$ 2,339,760	$ 1,807,358	$ 532,402	29 %
Selected Operating Expenses (per Boe):				
Lease operating expense	$ 3.89	$ 2.74	$ 1.15	42 %
Midstream operating expense[(1)]	0.58	0.51	0.07	14 %
Gathering, transportation, and processing	3.75	4.63	(0.88)	(19)%
Severance and ad valorem taxes	3.57	4.93	(1.36)	(28)%
Depreciation, depletion, and amortization	15.13	13.16	1.97	15 %
Transaction costs	1.09	0.40	0.69	173 %
General and administrative expense	2.08	2.31	(0.23)	(10)%
Total selected operating expenses (per Boe)	$ 30.09	$ 28.68	$ 1.41	5 %

(1) Our midstream assets relate entirely to our DJ Basin operations. If we were to exclude the production of our Permian Basin from this calculation, it would result in a $0.22 per Boe, or 43%, change period over period.

Lease operating expense. Our lease operating expense increased 77% to $301.3 million for the year ended December 31, 2023 from $170.0 million for the year ended December 31, 2022, and increased 42% on an equivalent basis per Boe. The increase in lease operating expense per Boe is primarily the result of the higher cost of chemical treatments and water disposal in the Permian Basin, specifically for wells in New Mexico as a result of the Tap Rock Acquisition, and the impact of inflation in areas such as labor, power, and rentals in the DJ Basin.

Midstream operating expense. Our midstream operating expense increased 41% to $45.1 million for the year ended December 31, 2023 from $31.9 million for the year ended December 31, 2022, and increased 14% on an equivalent basis per Boe. Midstream operating expense increased primarily due to approximately $5.0 million in maintenance services performed on compressors and piping as well as approximately $4.0 million from increases experienced in our labor costs.

Gathering, transportation, and processing. Gathering, transportation, and processing expense increased $3.2 million, or 1%, to $290.6 million for the year ended December 31, 2023 from $287.5 million for the year ended December 31, 2022, and decreased 19% on an equivalent basis per Boe. For a significant portion of the midstream contracts assumed with the Hibernia Acquisition and the Tap Rock Acquisition, gathering, transportation, and processing costs are incurred subsequent to the transfer of control; thereby, these costs are recorded net within crude oil and natural gas sales. As a result, gathering, transportation, and processing expense per Boe decreased period over period.

Severance and ad valorem taxes. Severance taxes represent taxes imposed by the states in which we operate based on the value of the crude oil, natural gas, and NGL we produce. Ad valorem taxes represent taxes imposed by specific jurisdictions in which we operate based on the assessed value of our properties in that region. For our operations in Texas, the assessed value of our properties is determined using a discounted cash flow methodology. For our operations in Colorado and New Mexico, assessed value is determined by the value of the crude oil, natural gas, and NGL sold less various costs incurred for transportation and processing.

Our severance and ad valorem taxes decreased 10% to $276.5 million for the year ended December 31, 2023 from $305.7 million for the year ended December 31, 2022, and decreased 28% on an equivalent basis per Boe. Product revenues decreased by 8% for the year ended December 31, 2023 when compared to the same period in 2022, resulting in lower severance and ad valorem taxes for the current year. Additionally, the incremental decrease in severance and ad valorem taxes per Boe is primarily due to an increase in product revenues generated through the Hibernia Acquisition in the state of Texas, which generally levies lower severance and ad valorem tax rates relative to Colorado and New Mexico.

Depreciation, depletion, and amortization. Our depreciation, depletion, and amortization expense ("DD&A") increased 43% to $1.2 billion for the year ended December 31, 2023 from $816.4 million for the year ended December 31, 2022, and increased 15% on an equivalent basis per Boe. During 2023 and 2022, we invested $5.2 billion and $1.3 billion, respectively, in the development and acquisition of crude oil and natural gas properties. DD&A related to crude oil and natural gas properties is directly related to proved reserves and sales volumes. The increase in total DD&A expense was primarily due to a 25% increase in sales volumes between periods driven by the Hibernia Acquisition and the Tap Rock Acquisition. Additionally, the increase in DD&A expense and DD&A expense per Boe is due to an increase in the depletion rate driven by an increase in the depletable property base in proportion to proved reserves.

Abandonment and impairment of unproved properties. During the year ended December 31, 2022, we incurred $18.0 million in abandonment and impairment of unproved properties due to our assessment over locations and the replacement of non-core legacy locations with newly acquired locations. No abandonment and impairment of unproved properties was incurred during the year ended December 31, 2023.

Transaction costs. During the year ended December 31, 2023, we incurred $84.3 million in short-term financing fees as well as legal, advisor, and other costs associated with the Hibernia Acquisition, Tap Rock Acquisition, and Vencer Acquisition. During the year ended December 31, 2022, we incurred $24.7 million in legal, advisor, and other costs associated with the Bison Acquisition (as defined below) and other mergers that closed in the fourth quarter of 2021. Please refer to "*Item 8. Financial Statements and Supplementary Data - Note 2 - Acquisitions and Divestitures*" for additional discussion.

General and administrative expense. Our general and administrative expense increased 12% to $161.1 million for the year ended December 31, 2023 from $143.5 million for the year ended December 31, 2022, and decreased 10% on an equivalent basis per Boe. The increase in general and administrative expense is primarily due to an increase in headcount and an increase in professional services, partially offset by a decrease in charitable contributions. General and administrative expense per Boe decreased due to total sales volumes increasing 25% during the year ended December 31, 2023 as compared to the same period in 2022.

Derivative gain (loss), net. Our derivative gain for the year ended December 31, 2023 of $9.3 million was due to fair market value adjustments resulting from lower market prices relative to our open positions, partially offset by cash settlement losses. Our derivative loss for the year ended December 31, 2022 of $335.2 million was due to cash settlement losses, partially offset by fair market value adjustment gains attributable to lower market prices relative to our open positions. Please refer to "*Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives*" for additional discussion.

Interest expense. Our interest expense for the years ended December 31, 2023 and 2022 was $182.7 million and $32.2 million, respectively. Average debt outstanding for the years ended December 31, 2023 and 2022 was $2.1 billion and $435.5 million, respectively. The components of interest expense for the periods presented are as follows (in thousands):

	Year Ended December 31,	
	2023	**2022**
Senior Notes	$ 154,607	$ 22,521
Credit Facility	12,100	115
Commitment and letter of credit fees under the Credit Facility	6,231	5,099
Amortization of deferred financing costs	9,293	4,464
Finance lease	509	—
Total interest expense	$ 182,740	$ 32,199

Income tax expense. Our income tax expense for the years ended December 31, 2023 and 2022 was $215.2 million and $405.7 million, resulting in an effective tax rate of 21.5% and 24.5% 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. Financial Statements and Supplementary Data - Note 12 - Income Taxes*" for additional discussion.

Liquidity and Capital Resources

Our 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, debt reduction, return of capital to stockholders, and for general corporate purposes.

Our primary source of cash flows from operating activities is the sale of crude oil, natural gas, and NGL. As such, our cash flows are subject to significant volatility due to changes in commodity prices, as well as variations in our sales 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, 2023, our liquidity was $2.2 billion, consisting of cash on hand of $1.1 billion and $1.1 billion of available borrowing capacity on our Credit Facility. Borrowing capacity under the Credit Facility is primarily based on the value assigned to the proved reserves attributable to our crude oil and natural gas interests. On August 2, 2023, we closed the Hibernia Acquisition and Tap Rock Acquisition and simultaneously entered into an amendment to the Credit Facility that increased our aggregate elected commitments from $1.0 billion to $1.85 billion, increased the borrowing base from $1.85 billion to $3.0 billion, and increased the aggregate maximum credit commitment from $2.0 billion to $4.0 billion. As of the date of filing of this report, the available borrowing capacity on our Credit Facility is $1.45 billion. In addition, the maturity of the Credit Facility was extended to August 2028. The next scheduled borrowing base redetermination date is set to occur in May 2024.

The Credit Facility contains customary representations and various affirmative and negative covenants as well as certain financial covenants, including (a) a maximum ratio of our 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 1.00 and (b) a current ratio, inclusive of the unused commitments then available to be borrowed, to not be less than 1.00 to 1.00. We were in compliance with all covenants under the Credit Facility as of December 31, 2023, and through the filing of this report. Please refer to "*Item 8. Financial Statements and Supplementary Data - Note 5 - Long-Term Debt*" for additional information.

Our material short-term cash requirements include: consideration for the Vencer Acquisition, operating activities, working capital requirements, capital expenditures, 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 leases. Please refer to "*Item 8. Financial Statements and Supplementary Data*" 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 crude oil and natural 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 2024 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, and based on current expectations, the long-term.

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

	Year Ended December 31,	
	2023	2022
Net cash provided by operating activities	$ 2,238,760	$ 2,477,041
Net cash used in investing activities	(5,243,155)	(1,306,095)
Net cash provided by (used in) financing activities	3,363,076	(657,368)
Cash, cash equivalents, and restricted cash	1,126,815	768,134
Acquisitions of businesses, net of cash acquired	(3,655,612)	(236,160)
Acquisitions of crude oil and natural gas properties	(154,855)	(97,453)
Exploration and development of crude oil and natural gas properties	(1,352,388)	(967,096)

Operating Activities

Our net cash flows from operating activities are primarily impacted by commodity prices, sales volumes, net settlements from our commodity derivative positions, operating costs, and general and administrative expenses. Net cash provided by operating activities decreased by $238.3 million to $2.2 billion in 2023 as compared to $2.5 billion in 2022, which was mainly attributable to decreases in commodity prices, higher operating costs and transaction costs, partially offset by lower net cash settlements of our derivative positions. See "*Results of Operations*" above for more information on the factors driving these changes.

Investing Activities

As crude oil and natural gas production from a well declines rapidly in the first few years of production, we need to continue to commit significant amounts of capital in order to maintain and grow our production and replace our crude oil and natural reserves. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our revolving credit facility as the sources for funding our capital investments.

Net cash used in investing activities of $5.2 billion for the year ended December 31, 2023 was primarily the result of (i) acquisitions of businesses, net of cash acquired of $3.7 billion; (ii) exploration and development of crude oil and natural gas properties of $1.4 billion; (iii) a deposit for acquisitions of $161.3 million; and (iv) acquisitions of crude oil and natural gas properties of $154.9 million. Total investing activities were partially offset by $90.5 million of proceeds from the sale of crude oil and natural gas properties.

Net cash used in investing activities of $1.3 billion for the year ended December 31, 2022 was primarily the result of the exploration and development of crude oil and natural gas properties of $967.1 million, acquisitions of businesses, net of cash acquired of $236.2 million, and acquisitions of crude oil and natural gas properties of $97.5 million.

Financing Activities

Net cash provided by financing activities of $3.4 billion for the year ended December 31, 2023 was primarily due to proceeds of $3.7 billion from the issuance of the 2028 Senior Notes, 2030 Senior Notes, and 2031 Senior Notes, and net borrowings on the Credit Facility of $750 million, partially offset by dividends paid of $660.3 million, the repurchase and retirement of common stock of $320.4 million, the payment of deferred financing costs of $45.8 million, and the payment of employee tax withholdings in exchange for the return of common stock of $13.4 million.

Net cash used in financing activities of $657.4 million for the year ended December 31, 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 the payment of employee tax withholdings in exchange for the return of common stock of $19.6 million.

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. See "*Item 8. Financial Statements and Supplementary Data - Note 5 - Long-Term Debt*" of this report 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 crude 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, 2023	Year Ended December 31, 2022
Net income	$ 784,288	$ 1,248,080
Exploration	2,178	6,981
Depreciation, depletion, and amortization	1,171,192	816,446
Abandonment and impairment of unproved properties	—	17,975
Unused commitments and other [(1)]	5,013	3,641
Transaction costs	84,328	24,683
Stock-based compensation [(2)]	34,931	31,367
Non-recurring general and administrative expense [(2)]	—	18,037
Derivative (gain) loss	(9,307)	335,160
Derivative cash settlement loss	(68,246)	(576,802)
Interest expense	182,740	32,199
Interest income [(3)]	(33,347)	—
(Gain) loss on property transactions, net	254	(15,880)
Income tax expense	215,166	405,698
Adjusted EBITDAX	$ 2,369,190	$ 2,347,585

(1) Included as a portion of other operating expense in the accompanying statements of operations.
(2) Included as a portion of general and administrative expense in the accompanying statements of operations.
(3) Included as a portion of other income in the accompanying 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 operating assets and liabilities and less exploration and development of crude oil and natural gas properties, changes in working capital related to capital expenditures, and purchases of carbon credits. 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 crude oil and natural gas assets to fund future exploration and development activities and to return cash to stockholders. 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, 2023	Year Ended December 31, 2022
Net cash provided by operating activities	$ 2,238,760	$ 2,477,041
Add back: Changes in operating assets and liabilities, net	(71,932)	(276,141)
Cash flow from operations before changes in operating assets and liabilities	2,166,828	2,200,900
Less: Exploration and development of crude oil and natural gas properties	(1,352,388)	(967,096)
Less: Changes in working capital related to capital expenditures	(12,349)	(7,679)
Less: Purchases of carbon credits and renewable energy credits	(6,151)	(7,298)
Free Cash Flow	$ 795,940	$ 1,218,827

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 crude oil and natural gas properties. We use this measure when assessing the potential return on investment related to our crude 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 crude 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):

	As of December 31,		
	2023	2022	2021
Standardized Measure	$ 8,269.3	$ 7,927.5	$ 4,412.1
Present value of future income taxes discounted at 10%	1,110.7	1,906.8	915.1
PV-10	$ 9,380.0	$ 9,834.3	$ 5,327.2

Reconciliation of average sales price, after derivatives

Average sales price, after derivatives is a non-GAAP financial measure that incorporates the net effect of derivative cash receipts from or payments on commodity derivatives that are presented in our statement of cash flows, netted into the average sales price, before derivatives, the most directly comparable GAAP financial measure. We believe that the presentation of average sales price, after derivatives is a useful means to reflect the actual cash performance of our commodity derivatives for the respective periods and is useful to management and our stockholders in determining the effectiveness of our price risk management program.

The following table provides a reconciliation of the GAAP financial measure of average sales price, before derivatives to the non-GAAP financial measure of average sales prices, after derivatives for the periods presented:

	Year Ended December 31,	
	2023	2022
Average crude oil sales price (per Bbl) (1)	$ 75.57	$ 91.70
Effects of derivatives, net (per Bbl) (3)	(1.62)	(12.53)
Average crude oil sales price (after derivatives) (per Bbl)	$ 73.95	$ 79.17
Average natural gas sales price (per Mcf) (2)	$ 2.28	$ 6.15
Effects of derivatives, net (per Mcf) (3)	(0.06)	(1.68)
Average natural gas sales price (after derivatives) (per Mcf)	$ 2.22	$ 4.47
Average NGL sales price (per Bbl)	$ 21.35	$ 35.76
Effects of derivatives, net (per Bbl) (3)	—	(2.62)
Average NGL sales price (after derivatives) (per Bbl)	$ 21.35	$ 33.14

(1) Crude oil sales excludes $1.3 million and $0.6 million of crude oil transportation revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2023 and 2022, respectively.

(2) Natural gas sales excludes $4.1 million and $3.2 million of gas gathering revenues from third parties, which do not have associated sales volumes, for the years ended December 31, 2023 and 2022, respectively.

(3) Derivatives economically hedge the price we receive for crude oil, natural gas, and NGL. For the year ended December 31, 2023, the derivative cash settlement loss for crude oil and natural gas was $59.5 million and $8.7 million, respectively. For the year ended December 31, 2022, the derivative cash settlement loss for crude oil, natural gas, and NGL was $346.4 million, $189.4 million, and $41.0 million, respectively. Please refer to "*Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives*" for additional disclosures.

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 consolidated 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. Financial Statements and Supplementary Data - Note 1 - Summary of Significant Accounting Policies*."

Crude Oil and Natural Gas Properties

Proved Properties. We account for our 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.

We assess 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, we estimate 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 sales volumes associated with proved developed producing reserves and risk-adjusted proved undeveloped 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 us or other market participants. If circumstances dictate that the carrying value of unproved properties may not be recoverable, we perform a recoverability test. If carrying values exceed undiscounted future net cash flows associated with probable and possible reserves, impairment is measured and recorded at fair value. Because there usually is a lack of quoted market prices for unproved properties, we estimate 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 sales volumes associated with probable and possible reserves. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

Crude Oil and Natural Gas Reserves. The successful efforts method of accounting outlined above inherently relies on the estimation of proved crude 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 crude oil and natural gas that cannot be precisely measured. Consequently, we engage a third-party petroleum consultant to prepare our estimates of crude oil and natural gas reserves. Significant inputs and engineering assumptions used in developing the estimates of proved crude oil and natural gas reserves include reserves volumes, future operating and development costs, historical commodity prices, and our 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. If the estimates of proved reserve quantities decline, the rate at which we record depletion expense will increase, which would reduce future net income. Changes in depletion rate calculations caused by changes in reserve quantities are made prospectively. In addition, a decline in reserve estimates may impact the outcome of our assessment of proved and unproved properties for impairment. Impairments are recorded in the period in which they are identified.

We cannot predict future commodity prices. However, we performed a sensitivity analysis on our proved reserve estimates as of December 31, 2023, to present a decrease of approximately 10% in crude oil and natural gas price (and holding all other factors constant), as the value of crude oil and natural gas influences the value of our proved reserves most significantly. As a result, our proved reserve quantities would decrease by 19.6 MMBoe or 3%. The reserve decrease would have increased our DD&A rate by $0.49 per Boe and decreased our pre-tax income by $38.1 million for the year ended December 31, 2023. This estimated impact is based on available data as of December 31, 2023, and future events could require different adjustments to our DD&A rate. There were no significant impairment charges recognized related to our proved and unproved properties during the years ended December 31, 2023 or 2022. For more information regarding reserve estimations, including additional crude oil sensitives and descriptions over historical reserve revisions, see "*Part I - Item 1. - Business*", "*Part I - Item 2. Properties*", and "*Item 8. Financial Statements and Supplementary Data - Note 16 - Disclosures About Oil and Gas Producing Activities*" included elsewhere in this report.

Business Combinations

As part of our business strategy, we regularly pursue the acquisition of crude 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. Any excess of the purchase price over the fair value amounts assigned to assets and liabilities is recorded as goodwill. Any deficiency of the purchase price over the estimated fair values of the net assets acquired is recorded as bargain purchase gain in the statements of operations.

During 2023, we accounted for two business combinations under the acquisition method of accounting, the Hibernia Acquisition and the Tap Rock Acquisition. 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, which resulted in $2.3 billion for the Hibernia Acquisition and $2.6 billion for the Tap Rock Acquisition. Because sufficient market data may not be available regarding the fair values of our acquired proved and unproved oil and gas properties, we engage a third-party valuation expert to assist in preparing the fair value estimates. We utilize 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, reserve adjustment factors, 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, reserve adjustment factors are applied to probable and possible reserves. The purchase price consideration for the Hibernia Acquisition and the Tap Rock Acquisition of $2.2 billion and $2.5 billion, respectively, was allocated to the assets acquired and liabilities assumed based upon their estimated acquisition date fair values and resulted in no goodwill or bargain purchase gain.

Estimated fair values ascribed to assets acquired can have a significant impact on future results of operations presented in our consolidated financial statements. For example, a higher fair value ascribed to 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 and increases the likelihood of future impairment charges.

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 4.1% in 2023, 8.0% in 2022, and 4.7% in 2021. During 2023 and 2022, we experienced cost inflation on labor, power and other key costs in our operations and development program, however, it did not have a material impact on our results of operations for the periods ended December 31, 2023, 2022, or 2021.

We tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing crude 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.***

Crude Oil and Natural Gas Price Risk

Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of crude 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 crude oil and natural gas prices include the level of global demand for crude oil and natural gas, the global supply of crude oil and natural gas, the establishment of and compliance with production quotas by crude 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 crude oil and natural gas prices with any degree of certainty. Sustained weakness in crude oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of crude oil and natural gas reserves that we can produce economically. Any reduction in our crude 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 crude oil and natural gas prices can have a favorable impact on our financial condition, results of operations, and capital resources. If crude oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 3% and our PV-10 value as of December 31, 2023 would decrease by approximately 18% or $1.6 billion. If crude oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 2% and our PV-10 value as of December 31, 2023 would increase by approximately 18% or $1.7 billion.

PV-10 is a non-GAAP financial measure. Please refer to "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Non-GAAP Financial Measures*" for management's discussion of this non-GAAP financial measure.

Commodity Price Derivative Contracts

Our primary commodity risk management objective is to protect our balance sheet. We periodically enter into derivative contracts for crude oil, natural gas, and NGL using NYMEX futures or over-the-counter derivative financial instruments. The types of derivative instruments that we use include swaps, collars, basis protection swaps, 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, 2023, a hypothetical upward or downward shift of 10% in the forward curve for the related indices would decrease our derivative gain by $81.1 million or increase it by $82.3 million, respectively. Please refer to "*Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives*" for summary derivative activity tables.

Interest Rates

As of December 31, 2023, we had a $750.0 million balance on our Credit Facility. As of the filing date of this report, we had a $400.0 million 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, 2023 and through the filing date of this report, we were in compliance with all financial and non-financial covenants under the Credit Facility.

Counterparty and Customer Credit Risk

In connection with our derivative activities, we have exposure to financial institutions in the form of derivative transactions. As of December 31, 2023, and the filing date of this report, our derivative contracts have been executed with 15 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 crude 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. Our allowances for credit losses were insignificant as of December 31, 2023.

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, 2023 and 2022, 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, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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, 2023, 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 27, 2024, 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 Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate 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 matters below, providing a separate opinion on the critical audit matters or on the accounts or disclosures to which they relate.

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.

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.

Acquisitions and Divestitures — Valuation of Oil and Gas Properties — Refer to Note 1 and Note 2 to the consolidated financial statements

Critical Audit Matter Description

As described in Note 2 to the consolidated financial statements, the Company acquired Hibernia Energy III, LLC & Hibernia Energy III-B, LLC ("Hibernia") and Tap Rock AcquisitionCo, LLC, Tap Rock Resources II, LLC, and Tap Rock NM10 Holdings, LLC ("Tap Rock") in acquisitions accounted for as business combinations, which required assets acquired and liabilities assumed to be measured at their acquisition date fair values, including the fair values of acquired oil and gas properties. Management applied significant judgment in estimating the fair value of oil and gas properties acquired, which involved the use of a discounted cash flow model that incorporated oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate.

The principal considerations for our determination that performing procedures relating to the valuation of oil and gas properties from the acquisitions of Hibernia and Tap Rock is a critical audit matter are (i) the significant judgments made by management, including the use of management's specialists as discussed in the previous Critical Audit Matter, as well the use of an independent accounting firm to estimate oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate when developing the fair value measurement of acquired oil and gas properties; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating significant assumptions of the nature discussed in the previous Critical Audit Matter, as well as assumptions used in the discounted cash flow model related to oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management's significant judgments and assumptions related to oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate included the following, among others:

- We tested the design, implementation, and operating effectiveness of controls related to the Company's assumptions related to oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate used within the valuation of acquired oil and gas properties.
- We evaluated the appropriateness of the discounted cash flow model by:

    - Testing the completeness and accuracy of underlying data used in the discounted cash flow model.
    - Evaluating the reasonableness of significant assumptions used by management related to oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate.
    - Utilizing professionals with specialized skill and knowledge to assist in the evaluation of the discounted cash flow model, including oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate used.

- We evaluated the experience, qualifications, and objectivity of management's experts, an independent accounting firm, including the methodologies used to estimate oil and natural gas price escalation factors, reserve adjustment factors and the weighted average cost of capital rate, as well as an independent reserve engineering firm as discussed in the previous Critical Audit Matter.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 27, 2024

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, 2023	As of December 31, 2022
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,124,797	$ 768,032
Accounts receivable, net:		
Crude oil and natural gas sales	505,961	343,500
Joint interest and other	247,228	135,816
Derivative assets	35,192	2,490
Prepaid income taxes	9,552	29,604
Deposits for acquisitions	163,164	—
Prepaid expenses and other	58,518	48,988
Total current assets	2,144,412	1,328,430
Property and equipment (successful efforts method):		
Proved properties	12,738,568	6,774,635
Less: accumulated depreciation, depletion, and amortization	(2,339,541)	(1,214,484)
Total proved properties, net	10,399,027	5,560,151
Unproved properties	821,939	593,971
Wells in progress	536,858	407,351
Other property and equipment, net of accumulated depreciation of $9,808 in 2023 and $7,329 in 2022	62,392	49,632
Total property and equipment, net	11,820,216	6,611,105
Derivative assets	8,233	794
Right-of-use assets	94,606	24,125
Other noncurrent assets	29,852	6,945
Total Assets	$ 14,097,319	$ 7,971,399
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 565,708	$ 295,297
Production taxes payable	421,045	258,932
Crude oil and natural gas revenue distribution payable	766,123	538,343
Derivative liability	18,096	46,334
Asset retirement obligations	31,116	25,557
Lease liability	45,298	13,464
Deferred revenue	4,501	—
Total current liabilities	1,851,887	1,177,927
Long-term liabilities:		
Senior notes, net	4,035,732	393,293
Credit facility	750,000	—
Ad valorem taxes	313,753	412,650
Derivative liability	—	17,199
Deferred income tax liabilities, net	564,781	319,618
Asset retirement obligations	305,716	265,469
Lease liability	50,240	11,324
Deferred revenue	43,889	—
Total liabilities	7,915,998	2,597,480
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, 93,774,901 and 85,120,287 issued and outstanding as of December 31, 2023 and 2022, respectively	5,004	4,918
Additional paid-in capital	4,964,450	4,211,197
Retained earnings	1,211,867	1,157,804
Total stockholders' equity	6,181,321	5,373,919
Total Liabilities and Stockholders' Equity	$ 14,097,319	$ 7,971,399

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

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

	Year Ended December 31,		
	2023	**2022**	**2021**
Operating net revenues:			
Crude oil, natural gas, and NGL sales	$ 3,479,240	$ 3,791,398	$ 930,614
Operating expenses:			
Lease operating expense	301,288	169,986	52,391
Midstream operating expense	45,080	31,944	17,426
Gathering, transportation, and processing	290,645	287,474	64,507
Severance and ad valorem taxes	276,535	305,701	65,113
Exploration	2,178	6,981	7,937
Depreciation, depletion, and amortization	1,171,192	816,446	226,931
Abandonment and impairment of unproved properties	—	17,975	57,260
Transaction costs	84,328	24,683	43,555
General and administrative expense (including $34,931, $31,367, and $15,558, respectively, of stock-based compensation)	161,077	143,477	65,132
Other operating expense	7,437	2,691	8,299
Total operating expenses	2,339,760	1,807,358	608,551
Other income (expense):			
Derivative gain (loss), net	9,307	(335,160)	(60,510)
Interest expense	(182,740)	(32,199)	(9,700)
Gain (loss) on property transactions, net	(254)	15,880	1,932
Other income (expense)	33,661	21,217	(2,006)
Total other expense	(140,026)	(330,262)	(70,284)
Income from operations before income taxes	999,454	1,653,778	251,779
Income tax expense	(215,166)	(405,698)	(72,858)
Net income	$ 784,288	$ 1,248,080	$ 178,921
Earnings per common share:			
Basic	$ 9.09	$ 14.68	$ 4.82
Diluted	$ 9.02	$ 14.58	$ 4.74
Weighted-average common shares outstanding			
Basic	86,240	85,005	37,155
Diluted	86,988	85,604	37,746

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	Retained	
	Shares	Amount	Capital	Earnings	Total
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	—	—	—	—
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
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
Issuance pursuant to acquisition	13,538,472	135	990,069	—	990,204
Restricted common stock issued	513,166	4	—	—	4
Stock used for tax withholdings	(180,154)	(1)	(13,416)	—	(13,417)
Exercise of stock options	13,928	—	459	—	459
Common stock repurchased and retired	(5,230,798)	(52)	(258,790)	(61,556)	(320,398)
Stock-based compensation	—	—	34,931	—	34,931
Cash dividends, $7.60 per share	—	—	—	(668,669)	(668,669)
Net income	—	—	—	784,288	784,288
Balances, December 31, 2023	93,774,901	$ 5,004	$ 4,964,450	$ 1,211,867	$ 6,181,321

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,		
	2023	**2022**	**2021**
Cash flows from operating activities:			
Net income	$ 784,288	$ 1,248,080	$ 178,921
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, and amortization	1,171,192	816,446	226,931
Abandonment and impairment of unproved properties	—	17,975	57,260
Stock-based compensation	34,931	31,367	15,558
Derivative (gain) loss, net	(9,307)	335,160	60,510
Derivative cash settlement loss	(68,246)	(576,802)	(275,914)
Amortization of deferred financing costs	9,293	4,464	1,890
(Gain) loss on property transactions, net	254	(15,880)	(1,932)
Deferred income tax expense	245,163	337,502	72,858
Other, net	(740)	2,588	90
Changes in operating assets and liabilities, net			
Accounts receivable, net	(39,869)	(941)	(100,881)
Prepaid expenses and other current assets	19,987	(34,025)	(3,338)
Accounts payable and accrued liabilities	126,215	335,563	47,510
Settlement of asset retirement obligations	(34,401)	(24,456)	(4,864)
Net cash provided by operating activities	2,238,760	2,477,041	274,599
Cash flows from investing activities:			
Acquisitions of businesses, net of cash acquired	(3,655,612)	(236,160)	222,442
Acquisitions of crude oil and natural gas properties	(154,855)	(97,453)	—
Deposits for acquisitions	(161,250)	—	—
Proceeds from sale of crude oil and natural gas properties	90,456	2,355	—
Exploration and development of crude oil and natural gas properties	(1,352,388)	(967,096)	(151,500)
Proceeds from (additions to) other property and equipment	(1,892)	(579)	2,393
Purchases of carbon credits and renewable energy credits	(6,151)	(7,298)	—
Other, net	(1,463)	136	212
Net cash provided by (used in) investing activities	(5,243,155)	(1,306,095)	73,547
Cash flows from financing activities:			
Proceeds from credit facility	2,120,000	100,000	155,000
Payments to credit facility	(1,370,000)	(100,000)	(589,000)
Proceeds from issuance of senior notes	3,653,750	—	400,000
Payment of deferred financing costs	(45,788)	(1,174)	(19,292)
Redemption of senior notes	—	(100,000)	—
Dividends paid	(660,320)	(536,922)	(60,780)
Common stock repurchased and retired	(320,398)	—	—
Proceeds from exercise of stock options	459	308	1,585
Payment of employee tax withholdings in exchange for the return of common stock	(13,416)	(19,580)	(5,927)
Principal payments on finance lease obligations	(1,211)	—	(21)
Net cash provided by (used in) financing activities	3,363,076	(657,368)	(118,435)
Net change in cash, cash equivalents, and restricted cash	358,681	513,578	229,711
Cash, cash equivalents, and restricted cash:			
Beginning of period [(1)]	768,134	254,556	24,845
End of period [(1)]	$ 1,126,815	$ 768,134	$ 254,556

[(1)] Includes $2.0 million of restricted cash and consists of $1.9 million of interest earned on cash held in escrow that is presented in deposits for acquisitions within the accompanying balance sheets for the period ended December 31, 2023 and $0.1 million of funds for road maintenance and repairs that is presented in other noncurrent assets within the accompanying balance sheets for all periods presented.

Please refer to *Note 14* for *Supplemental Disclosures of Cash Flow Information.*

The accompanying notes are an integral part of these 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 crude oil and associated liquids-rich natural gas primarily in the DJ Basin in Colorado and the Permian Basin in Texas and New Mexico.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of Civitas 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. In connection with the preparation of the accompanying consolidated financial statements, we evaluated events subsequent to the balance sheet date of December 31, 2023, through the filing date of this report. Additionally, certain prior period insignificant amounts have been reclassified to conform to current period presentation in the accompanying consolidated financial statements. Such reclassifications did not have a material impact on prior period consolidated financial statements.

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 consolidated financial statements. Actual results could differ from those estimates.

Industry Segment and Geographic Information

We operate in one industry segment, which is the acquisition, development, and production of crude oil and associated liquids-rich natural gas. All of our operations are conducted in the continental United States.

Cash and Cash Equivalents

We consider 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. We maintained cash balances in excess of federal deposit insurance limits as of December 31, 2023 and 2022, potentially subjecting us 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, Net

Our accounts receivable primarily consists of receivables due from purchasers of crude oil, natural gas, and NGL production and from joint interest owners on properties we operate. We are 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 and may be similarly affected by changes in economic and financial conditions, commodity prices, or other conditions. Generally, payments for production are collected within one to two months. For receivables due from joint interest owners, we generally have the ability to withhold future revenue disbursements to recover non-payment of joint interest billings.

We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil, natural gas, and NGL are fungible products with well-established markets and numerous purchasers. For the periods presented below, the following purchasers of our production accounted for more than 10% of our revenue as follows:

	Year Ended December 31,		
	2023	2022	2021
Customer A	16 %	6 %	15 %
Customer B	28 %	50 %	43 %
Customer C	5 %	10 %	13 %
Customer D	1 %	12 %	2 %

Property and Equipment

Proved Properties. We account for our 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. We have determined that we have three unit-of-production fields: the DJ Basin, the Midland Basin, and the Delaware Basin. In making these conclusions we consider the geographic concentration, operating similarities within the areas, geologic considerations and common cost environments in these areas. During the years ended December 31, 2023, 2022, and 2021, we incurred depletion expense of $1.1 billion, $773.5 million, and $212.5 million, respectively.

We assess proved properties for impairment whenever events or circumstances indicate that their carrying value may not be recoverable. An impairment loss is indicated if carrying values exceed undiscounted future net cash flows. If an impairment is incurred, the loss recognized is the excess of the carrying amount over fair value. Due to a lack of quoted market prices for proved properties, we estimate 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 sales volumes associated with proved developed reserves and risk-adjusted proved undeveloped reserves.

As of December 31, 2023 and 2022, the net book value of our midstream assets in the accompanying balance sheets was $339.9 million and $326.8 million, respectively. Depreciation on the 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. During the years ended December 31, 2023, 2022, and 2021, we incurred depreciation expense on our midstream assets of $12.3 million, $10.8 million, and $7.3 million, respectively.

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 are 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 us or other market participants. If circumstances dictate that the carrying value of unproved properties may not be recoverable, we perform a recoverability test. If carrying values exceed undiscounted future net cash flows associated with probable and possible reserves, impairment is measured and recorded at fair value. Because there usually is a lack of quoted market prices for unproved properties, we estimate 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 sales volumes associated with probable and possible reserves. Changes in our assumptions of the estimated nonproductive portion of our undeveloped leases could result in additional impairment expense.

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.

Crude 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 crude oil and natural gas that cannot be precisely measured. Consequently, we engage third-party independent reserve engineers, Ryder Scott, to prepare our estimates of crude oil and natural gas reserves. Significant inputs and engineering assumptions used in developing the estimates of proved crude oil and natural gas reserves include reserves volumes, future operating and development costs, historical commodity prices, and our 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 and unproved properties.

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

We evaluate contractual arrangements at inception to determine if it is a lease or contains an identifiable lease component. We recognize operating and finance leases with terms greater than 12 months on the accompanying balance sheets. 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 contractual arrangement, we apply 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. As we do 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 Credits and Renewable Energy Credits

We periodically purchase carbon credits and renewable energy credits as a means to address greenhouse gas emissions generated by our operations and purchased electricity that were not otherwise reduced or eliminated. Commensurate with their use, purchased carbon credits 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 credits and renewable energy credits are expensed when applied to our greenhouse gas emissions through depletion, depreciation, and amortization expense on the accompanying statements of operations. Purchased carbon credits 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 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 on the accompanying statements of operations using the effective interest method over the life of the respective borrowings.

Asset Retirement Obligations

We recognize 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 our crude 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. We recognize 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 our 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 our total asset retirement obligation liability as of December 31, 2023 and 2022.

Derivatives

We periodically enter into commodity derivative contracts to mitigate a portion of our exposure to potentially adverse market changes in commodity prices for our expected future crude oil and natural gas production and the associated impact on cash flows. Our commodity derivative contracts consist of swaps, collars, basis protection swaps, and puts. The crude 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, before differentials. As of December 31, 2023, all derivative counterparties were members of the Credit Facility lender group and all commodity derivative contracts are entered into for other-than-trading purposes. We do not designate our 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. We measure the fair value of our 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 our commodity price derivative instruments are recorded in the accompanying statements of operations as they occur.

As of December 31, 2023 and 2022, all of our derivative instruments are subject to master netting arrangements with various financial institutions. In general, the terms of our 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. Our 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. Our accounting policy is to not offset these positions and therefore report our derivative asset and liability positions on a gross basis in the accompanying balance sheets.

Derivative (gain) loss as well as derivative cash settlement 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

We recognize revenue from the sale of produced crude oil, natural gas, and NGL at the point in time when control of produced crude oil, natural gas, or NGL volumes transfer to the purchaser, which may differ depending on the applicable contractual terms. We consider 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 crude 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 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 subsequent to the transfer of control are recorded net within crude oil, natural gas, and NGL sales on the accompanying statements of operations.

Crude oil sales. Under our crude purchase and marketing contracts, we deliver production at the wellhead or other contractually agreed-upon downstream delivery points and collect an agreed-upon index price, net of pricing differentials.

Natural gas and NGL sales. Under our natural gas processing contracts, we deliver 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 us for the resulting sales of NGL and residue gas.

For the contracts where we maintain control through the tailgate of the midstream processing facility, we recognize 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 we relinquish control at the inlet of the midstream processing facility, we recognize natural gas and NGL revenues based on the contracted amount of the proceeds received from the midstream processing entity and, as a result, recognize revenue on a net basis.

In certain natural gas processing agreements, we may elect to take our residue gas and/or NGL in-kind at the tailgate of the midstream entity's processing plant and subsequently market the product. Through the marketing process, we deliver product to the third-party purchaser at a contractually agreed-upon delivery point and receive a specified index price from the third-party purchaser. In this scenario, we recognize 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.

We record 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, we record a revenue accrual based on, amongst other factors, an estimate of the volumes delivered at estimated prices as determined by the applicable contractual terms. We record the differences between our 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

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

Income Taxes

We account 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.

We recognize 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. Our 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.

Please refer to *Note 12 - Income Taxes* for additional discussion.

Earnings Per Share

We use 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 crude 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

Our 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, our commodity price derivative instruments are recorded at fair value. Our Senior Notes, as defined in *Note 5 - Long-Term Debt*, are recorded at cost, net of any unamortized discount and unamortized deferred financing costs, and their respective fair values are disclosed in *Note 8 - Fair Value Measurement*s. The recorded value of our 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. Our 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 we 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

In November 2023, the FASB issued ASU No. 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures ("ASU 2023-07"). ASU 2023-07 was issued to improve the disclosures about a public entity's reportable segments and to provide additional, more detailed information about a reportable segment's expenses. ASU 2023-07 is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. The guidance is to be applied on a retrospective basis to all prior periods presented in the financial statements. The Company is within the scope of this ASU and is evaluating the impact of this ASU on its consolidated financial statement disclosures.

In December 2023, the FASB issued ASU No. 2023-09, Improvements to Income Tax Disclosures ("ASU 2023-09"). ASU 2023-09 is intended to improve income tax disclosures primarily through enhanced disclosure of income tax rate reconciliation items, and disaggregation of income (loss) from continuing operations, income tax expense (benefit) and income taxes paid, net disclosures by federal, state and foreign jurisdictions, among others. This ASU is effective for annual reporting periods beginning after December 15, 2024, and early adoption is permitted. ASU 2023-07 should be applied on a prospective basis, and retrospective application is permitted. We are evaluating the impact that ASC 2023-09 will have on the consolidated financial statements and our plan for adoption, including the adoption date and transition method.

As of the filing of this report, the Company has not elected to early adopt ASU 2023-07 or ASU 2023-09. There are no other accounting standards applicable to us that would have a material effect on our consolidated financial statements and disclosures that have been issued but not yet adopted by us as of December 31, 2023, and through the filing date of this report.

NOTE 2 - ACQUISITIONS AND DIVESTITURES

All mergers and acquisitions disclosed below are accounted for under the acquisition method of accounting for business combinations under ASC Topic 805, *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, while transaction and integration costs associated with the acquisition 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. The fair values of crude oil and natural gas properties were measured using valuation techniques that converted future cash flows to a single discounted amount. Significant inputs to the valuation of the crude oil and natural gas properties included estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows, reserve adjustment factors, and a market-based weighted-average cost of capital. These inputs required significant judgments and estimates by management at the time of the valuation.

Hibernia Acquisition

On August 2, 2023, we acquired all of the issued and outstanding equity ownership interests of Hibernia Energy III, LLC and Hibernia Energy III-B, LLC (the "Hibernia Acquisition") for aggregate consideration of approximately $2.2 billion in cash, inclusive of customary post-closing adjustments. The following table presents the preliminary purchase price allocation of the assets acquired and the liabilities assumed in the Hibernia Acquisition:

Preliminary Purchase Price Allocation (in thousands)

Assets Acquired		
Cash and cash equivalents	$	30,671
Accounts receivable - crude oil and natural gas sales		89,766
Accounts receivable - joint interest and other		4,463
Proved properties		2,135,085
Unproved properties		115,802
Other property and equipment		520
Right-of-use assets		30,393
Total assets acquired	$	2,406,700
Liabilities Assumed		
Accounts payable and accrued expenses	$	97,739
Production taxes payable		10,320
Crude oil and natural gas revenue distribution payable		75,267
Asset retirement obligations		8,299
Lease liability		30,393
Total liabilities assumed		222,018
Net assets acquired	$	2,184,682

Through December 31, 2023, there have been immaterial adjustments made to the allocation presented in the Quarterly Report on Form 10-Q for the quarter ended September 30, 2023 filed with the SEC on November 7, 2023. The purchase price allocation for the Hibernia Acquisition is preliminary, and we continue to assess the fair values of certain of the Hibernia assets acquired and liabilities assumed. We expect to finalize the purchase price allocation as soon as practicable, which will not extend beyond the one-year measurement period.

Tap Rock Acquisition

On August 2, 2023, we acquired all of the issued and outstanding equity ownership interests of Tap Rock AcquisitionCo, LLC, Tap Rock Resources II, LLC, and Tap Rock NM10 Holdings, LLC (the "Tap Rock Acquisition") for aggregate consideration of approximately $2.5 billion, inclusive of customary post-closing adjustments. The following tables present the consideration transferred and preliminary purchase price allocation of the assets acquired and the liabilities assumed in the Tap Rock Acquisition:

Consideration (in thousands, except per share amount)		
Cash consideration	$	1,508,143
Shares of common stock issued		13,538,472
Closing price per share[1]	$	73.14
Equity consideration	$	990,204
Total consideration	$	2,498,347

[1] Based on the closing stock price of Civitas common stock on August 2, 2023.

Preliminary Purchase Price Allocation (in thousands)

Assets Acquired		
Cash and cash equivalents	$	6,543
Accounts receivable - crude oil and natural gas sales		106,255
Accounts receivable - joint interest and other		31,715
Prepaid expenses and other		17,930
Proved properties		2,335,333
Unproved properties		298,859
Other property and equipment		12,827
Right-of-use assets		626
Total assets acquired	$	2,810,088
Liabilities Assumed		
Accounts payable and accrued expenses	$	150,138
Production taxes payable		9,692
Crude oil and natural gas revenue distribution payable		68,094
Ad valorem taxes		1,407
Asset retirement obligations		31,518
Lease liability		626
Deferred revenue		50,266
Total liabilities assumed		311,741
Net assets acquired	$	2,498,347

Through December 31, 2023, there have been immaterial adjustments made to the allocation presented in the Quarterly Report on Form 10-Q for the quarter ended September 30, 2023 filed with the SEC on November 7, 2023. The purchase price allocation for the Tap Rock Acquisition is preliminary, and we continue to assess the fair values of certain of the Tap Rock assets acquired and liabilities assumed. We expect to finalize the purchase price allocation as soon as practicable, which will not extend beyond the one-year measurement period.

Revenue and earnings of the acquirees

The results of operations for the Hibernia Acquisition and Tap Rock Acquisition since the closing date have been included on our consolidated financial statements during the year ended December 31, 2023. The amount of revenue of Hibernia and Tap Rock included in our accompanying statements of operations was approximately $312.7 million and $410.4 million, respectively, during the year ended December 31, 2023. We determined that disclosing the amount of Hibernia and Tap Rock related net income included in the accompanying statements of operations is impracticable as the operations from these acquisitions were integrated into our operations 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, 2023 and 2022, assuming the Hibernia Acquisition and Tap Rock Acquisition had been completed as of January 1, 2022. The pro forma financial information is not necessarily indicative of the results of operations that would have been achieved if the Hibernia Acquisition and Tap Rock Acquisition had been effective as of this date, or of future results, and includes certain nonrecurring pro forma adjustments that were directly related to these business combinations.

	Year Ended December 31,	
	2023	2022
Total revenue	$ 4,433,121	$ 5,808,411
Net income	929,731	1,821,139
Earnings per common share - basic	$ 9.87	$ 18.48
Earnings per common share - diluted	9.79	18.37

Bison Acquisition

On March 1, 2022, we completed the acquisition of privately held DJ Basin operator Bison Oil & Gas II, LLC (“Bison”) for 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.

Vencer Acquisition

On October 3, 2023, we entered into a purchase and sale agreement (the “PSA”) with Vencer Energy, LLC (“Vencer”), pursuant to which we agreed to acquire from Vencer certain oil and gas properties, interests, and related assets located in Glasscock, Martin, Midland, Reagan, and Upton Counties, Texas (the “Assets”). In connection with and upon execution of the PSA, the Company deposited with an escrow agent a cash deposit of $161.3 million equal to 7.5% of the unadjusted Vencer Purchase Price (as defined below).

On January 2, 2024, we completed the transactions contemplated by the PSA (the “Vencer Acquisition”) for adjusted aggregate consideration of approximately $2.05 billion, which was comprised of (i) $1.0 billion in cash, subject to certain customary purchase price adjustments set forth in the PSA, (ii) 7,289,515 shares of common stock, par value $0.01 per share, valued at approximately $500.0 million, subject to certain customary anti-dilution and purchase price adjustments, and (iii) $550.0 million in cash to be paid on or before January 3, 2025 (as adjusted, the “Vencer Purchase Price”). All amounts deposited were applied towards the aggregate cash consideration due at the closing of the Vencer Acquisition.

The preliminary purchase price allocation for the Vencer Acquisition is not complete as of the date of this report. We expect to finalize the purchase price allocation as soon as practicable, which will not extend beyond the one-year measurement period.

Transaction costs

Transaction costs related to the aforementioned acquisitions are accounted for separately from the assets acquired and liabilities assumed and are included in transaction costs in the accompanying statements of operations. We incurred transaction costs of $84.3 million, $24.7 million, and $43.6 million during the years ended December 31, 2023, 2022, and 2021, respectively.

NOTE 3 - REVENUE RECOGNITION

Crude oil, natural gas, and NGL 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 and operating region is disaggregated below (in thousands):

	Year Ended December 31,						
	2023			2022		2021	
	DJ Basin	Permian Basin(2)	Total	DJ Basin	Total	DJ Basin	Total
Operating net revenues:							
Crude oil	$ 2,141,936	$ 634,756	$ 2,776,692	$ 2,536,134	$ 2,536,134	$ 614,811	$ 614,811
Natural gas	284,670	25,050	309,720	695,079	695,079	144,708	144,708
NGL	326,675	66,153	392,828	560,185	560,185	171,095	171,095
Crude oil, natural gas, and NGL sales	$ 2,753,281	$ 725,959	$ 3,479,240	$ 3,791,398	$ 3,791,398	$ 930,614	$ 930,614

(1) Represents revenue attributable to the Hibernia Acquisition and Tap Rock Acquisition for the period from August 2, 2023 through December 31, 2023.

For the years ended December 31, 2023, 2022, and 2021 revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was insignificant. As of December 31, 2023 and December 31, 2022, our receivables from contracts with customers were $506.0 million and $343.5 million, respectively.

NOTE 4 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

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

	As of December 31,	
	2023	2022
Accounts payable trade	$ 55,750	$ 31,783
Accrued drilling and completion costs	149,520	137,171
Accrued lease operating expense	80,423	18,109
Accrued gathering, transportation, and processing	69,060	59,398
Accrued general and administrative expense	30,095	20,054
Accrued transaction costs	8,796	—
Accrued commodity derivative settlements	1,580	12,514
Accrued interest expense	141,401	5,509
Other accrued expenses	29,083	10,759
Total accounts payable and accrued expenses	$ 565,708	$ 295,297

NOTE 5 - LONG-TERM DEBT

Senior Notes

Senior Notes are recorded net of unamortized discount and unamortized deferred financing costs within senior notes on the accompanying balance sheets, with no associated premiums. The table below presents the related carrying values as of December 31, 2023 (in thousands):

	As of December 31, 2023					
	Interest Rate	Interest payment Dates	Principal Amount	Unamortized Discount	Unamortized Deferred Financing Costs	Principal Amount, Net
2026 Senior Notes	5.000 %	April 15, October 15	$ 400,000	$ —	$ 5,071	$ 394,929
2028 Senior Notes	8.375 %	January 1, July 1	1,350,000	15,932	5,605	1,328,463
2030 Senior Notes	8.625 %	May 1, November 1	1,000,000	12,283	3,317	984,400
2031 Senior Notes	8.750 %	January 1, July 1	1,350,000	16,319	5,741	1,327,940
Total			$ 4,100,000	$ 44,534	$ 19,734	$ 4,035,732

2030 Senior Notes. On October 17, 2023, we issued $1.0 billion aggregate principal amount of 8.625% Senior Notes due November 1, 2030 (the “2030 Senior Notes”), among us, Computershare Trust Company, N.A., as trustee, and the guarantors party thereto. Upon issuance of the 2030 Senior Notes, we received net proceeds of $987.5 million after deducting fees of $12.5 million. The net proceeds, together with cash on hand, funded a portion of the consideration for the Vencer Acquisition.

At any time prior to November 1, 2026, we may redeem all or part of the 2030 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 November 1, 2026, we may redeem all or part of the 2030 Senior Notes at redemption prices (expressed as percentages of the principal amount redeemed) equal to (i) 104.313% for the twelve-month period beginning on November 1, 2026; (ii) 102.156% for the twelve-month period beginning on November 1, 2027; and (iii) 100.000% for the period beginning November 1, 2028 and at any time thereafter, plus accrued and unpaid interest, if any, to, but excluding, the redemption date (subject to the right of the noteholders on the relevant record date to receive interest on the relevant interest payment date).

We may redeem up to 35% of the aggregate principal amount of the 2030 Senior Notes at any time prior to November 1, 2026 with an amount not to exceed the net cash proceeds from certain equity offerings at a redemption price equal to 108.625% of the principal amount of the 2030 Senior Notes redeemed, plus accrued and unpaid interest, if any, provided, however, that (i) at least 65.0% of the aggregate principal amount of 2030 Senior Notes originally issued on the issue date (but excluding 2030 Senior Notes held by us and our subsidiaries) remains outstanding immediately after the occurrence of such redemption (unless all such 2030 Senior Notes are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days after the date of the closing of such equity offering.

2028 Senior Notes and 2031 Senior Notes. On June 29, 2023, we issued $1.35 billion aggregate principal amount of 8.375% Senior Notes due July 1, 2028 (the “2028 Senior Notes”), among us, Computershare Trust Company, N.A., as trustee, and the guarantors party thereto, and $1.35 billion aggregate principal amount of 8.750% Senior Notes due July 1, 2031 (the “2031 Senior Notes”), among us, Computershare Trust Company, N.A., as trustee. Upon issuance of the 2028 Senior Notes and 2031 Senior Notes, we received net proceeds of $2.67 billion after deducting fees of $33.8 million. The net proceeds, together with cash on hand and borrowings under the Credit Facility (as defined below), were used to fund a portion of the consideration for the Hibernia Acquisition and Tap Rock Acquisition.

At any time prior to July 1, 2025, we may redeem all or part of the 2028 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 July 1, 2025, we may redeem all or part of the 2028 Senior Notes at redemption prices (expressed as percentages of the principal amount redeemed) equal to (i) 104.188% for the twelve-month period beginning on July 1, 2025; (ii) 102.094% for the twelve-month period beginning on July 1, 2026; and (iii) 100.000% for the period beginning July 1, 2027 and at any time thereafter, plus accrued and unpaid interest, if any to, but excluding the redemption date.

At any time prior to July 1, 2026, we may redeem all or part of the 2031 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 July 1, 2026, we may redeem all or part of the 2031 Senior Notes at redemption prices (expressed as percentages of the principal amount redeemed) equal to (i) 104.375% for the twelve-month period beginning on July 1, 2026; (ii) 102.188% for the twelve-month period beginning on July 1, 2027; and (iii) 100.000% for the period beginning July 1, 2028 and at any time thereafter, plus accrued and unpaid interest, if any.

We may redeem up to 35% of the aggregate principal amount of the 2028 Senior Notes or 2031 Senior Notes at any time prior to July 1, 2025 or 2026, respectively, with an amount not to exceed the net cash proceeds from certain equity offerings at a redemption price equal to 108.375%, with respect to the 2028 Senior Notes, and 108.750%, with respect to the 2031 Senior Notes, of the principal amount of such series of 2028 Senior Notes and 2031 Senior Notes redeemed, plus accrued and unpaid interest, if any, provided, however, that (i) at least 65.0% of the aggregate principal amount of 2028 Senior Notes and 2031 Senior Notes of such series originally issued on the issue date (but excluding the 2028 Senior Notes and 2031 Senior Notes of such series held by us and our subsidiaries) remains outstanding immediately after the occurrence of such redemption (unless all such 2028 Senior Notes and 2031 Senior Notes are redeemed substantially concurrently) and (ii) the redemption occurs within 180 days after the date of the closing of such equity offering.

2026 Senior Notes. On October 13, 2021, we issued $400.0 million aggregate principal amount of 5.000% Senior Notes due November 1, 2026 (the “2026 Senior Notes”), among us, Wells Fargo Bank, National Association, as trustee, and the guarantors party thereto. As of December 31, 2022, we had unamortized deferred financing costs of $6.7 million and total principal amount, net outstanding of $393.3 million.

On or after October 15, 2023, we may redeem all or part of the 2026 Senior Notes at redemption prices equal to (i) 102.500% for the twelve-month period beginning on October 15, 2023; (ii) 101.250% for the twelve-month period beginning on October 15, 2024; and (iii) 100.000% for the twelve-month period beginning October 15, 2025 and at any time thereafter, plus accrued and unpaid interest, if any.

Guarantees. The 2026 Senior Notes, 2028 Senior Notes, 2030 Senior Notes, 2031 Senior Notes, (collectively, the “Senior Notes”) are fully and unconditionally guaranteed on a senior unsecured basis by all of our existing subsidiaries and are expected to be guaranteed by certain other future subsidiaries that may be required to guarantee the Senior Notes.

The indentures governing the Senior Notes contain covenants that limit, among other things, our ability and the ability of our subsidiaries 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 our subsidiaries to pay dividends to us; (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. We were in compliance with all covenants and all restricted payment provisions related to our Senior Notes through the filing of this report.

7.500% 2026 Senior Notes. In 2021, we issued $100.0 million aggregate principal amount of 7.500% Senior Notes due 2026 by and among us, U.S. Bank National Association, as trustee, and the guarantors party thereto. In May 2022, we redeemed all of the issued and outstanding 2026 Senior Notes at 100.0% of their aggregate principal amount, plus accrued and unpaid interest thereon to the redemption date.

Credit Facility

We are 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, as lenders, that has an aggregate maximum commitment amount of $4.0 billion and is set to mature on August 2, 2028 (together with all amendments thereto, the “Credit Facility” or the “Credit Agreement”).

The Credit Facility is guaranteed by all our restricted domestic subsidiaries 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 crude oil and natural gas properties of our restricted domestic subsidiaries, 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, we are 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 1.00 and (b) a current ratio, inclusive of the unused commitments then available to be borrowed, to not be less than 1.00 to 1.00. Borrowings under the Credit Facility bear interest at a per annum rate equal to, at our option, either (i) the Alternate Base Rate ("ABR", for ABR revolving credit loans) plus the applicable margin, or (ii) the term-specific Secured Overnight Financing Rate ("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 us 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 are payable on the last day of the applicable interest period selected by us, and interest on borrowings that bear interest at the ABR are payable quarterly in arrears.

In connection with the Hibernia Acquisition and the Tap Rock Acquisition, we entered into amendments to the Credit Agreement. Pursuant to the amendments, we were authorized to, among other things, (i) offer and issue the 2028 Senior Notes and the 2031 Senior Notes, (ii) incur indebtedness pursuant to those certain debt commitment letters by and among us, Bank of America N.A., BofA Securities, Inc., and JPMorgan Chase Bank, N.A. providing for two separate 364-day bridge loan facilities in an aggregate principal amount of up to $2.7 billion (such facilities, the "Bridge Facilities" and the loans made thereunder, the "Bridge Loans"), the proceeds of which would have, if drawn, been used to partially fund the Hibernia Acquisition and the Tap Rock Acquisition, (iii) incur the debt described in the immediately preceding clauses (i) and (ii) without any corresponding reduction in the borrowing base of the Credit Facility, (iv) aggregate elected commitments increased from $1.0 billion to $1.85 billion, the borrowing base increased from $1.85 billion to $3.0 billion, and the aggregate maximum credit commitment increased from $2.0 billion to $4.0 billion and (v) incur pari passu term loan indebtedness subject to a total secured leverage test of 2.00 to 1.00 and certain other customary terms and conditions.

Because the 2028 Senior Notes and 2031 Senior Notes successfully closed, we did not draw on the Bridge Loans and have terminated the commitments under the Bridge Facilities. Consequently, $21.0 million of fees associated with the Bridge Facilities in relation to the Hibernia and Tap Rock acquisitions were incurred and expensed to transaction costs in the accompanying statements of operations for the year ended December 31, 2023.

In addition, the maturity of the Credit Facility was extended to August 2028. The next scheduled borrowing base redetermination date is set to occur in May 2024.

Finally, in connection with the entry into the Vencer Acquisition Agreement, on October 6, 2023, we entered into an amendment to the Credit Agreement (the "Fifth Amendment"). The Fifth Amendment amends the Credit Agreement to, among other things, permit us to incur an aggregate of up to $1.5 billion of indebtedness comprised of new senior unsecured notes, unsecured Bridge Facilities or a combination thereof, provided the proceeds therefrom are used to fund the transactions contemplated by the Purchase and Sale Agreement, dated October 3, 2023, by and between us and Vencer Energy, LLC. The Fifth Amendment additionally effectuates certain other modifications to the Credit Agreement, including (a) amending the general indebtedness basket therein to (i) increase the pro forma leverage restriction applicable thereto from 2.50 to 1.00 to 3.00 to 1.00 and (ii) include carveouts for customary bridge facilities and bonds with customary mandatory redemption provisions (in each case, not tied to any specific acquisition), (b) amending the general restricted payment basket therein to (i) increase the pro forma leverage restriction applicable thereto from 1.75 to 1.00 to 3.00 to 1.00 and (ii) increase the pro forma maximum utilization percentage restriction applicable thereto from 75% to 80%, (c) amending the general investment basket therein to (i) increase the pro forma leverage restriction applicable thereto from 1.00 to 1.00 to 3.00 to 1.00, and (ii) increase the pro forma maximum utilization percentage restriction applicable thereto from 75% to 80%, (d) amending the general basket for the covenant regarding prepayments of certain other indebtedness to increase the pro forma leverage restriction applicable thereto from 1.00 to 1.00 to 3.00 to 1.00 and (e) removing the minimum hedging affirmative covenant therein. We were in compliance with all covenants under the Credit Facility as of December 31, 2023 and through the filing of this report. Because the 2030 Senior Notes successfully closed and were issued on October 17, 2023, we did not draw on the Bridge Loans and have terminated the commitments under the Bridge Facilities. Consequently, $7.6 million of fees associated with the Bridge Facilities in relation to the Vencer acquisition were incurred and expensed to transaction costs in the accompanying statements of operations for the year ended December 31, 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 27, 2024	December 31, 2023	December 31, 2022
Credit Facility	$ 400,000	$ 750,000	$ —
Letters of credit	2,100	2,100	12,100
Available borrowing capacity	1,447,900	1,097,900	987,900
Total aggregate elected commitments	$ 1,850,000	$ 1,850,000	$ 1,000,000

As of December 31, 2023 and 2022, the unamortized deferred financing costs associated with the amendments to the Credit Facility were $34.4 million and $8.5 million, respectively. Of the unamortized deferred financing costs, (i) $26.9 million and $5.5 million are presented within other noncurrent assets on the accompanying balance sheets as of December 31, 2023 and 2022, respectively, and (ii) $7.5 million and $3.0 million are presented within prepaid expenses and other on the accompanying balance sheets as of December 31, 2023 and 2022, respectively.

Interest Expense

For the years ended December 31, 2023, 2022, and 2021, we incurred interest expense of $182.7 million, $32.2 million, and $9.7 million respectively.

NOTE 6 - COMMITMENTS AND CONTINGENCIES

Commitments

Firm Transportation Agreements. We are party to a firm pipeline transportation contract to provide a guaranteed outlet for production on an oil pipeline system. The contract requires us to pay minimum volume transportation charges on 12,500 Bbls per day through April 2025, regardless of the amount of pipeline capacity utilized. The aggregate financial commitment fee over the remaining term was $25.4 million as of December 31, 2023. We have not and do not expect to incur any deficiency payments.

Minimum Volume Agreement - Crude Oil. We are party to a transportation services agreement to deliver fixed and determinable quantities of crude oil. Under the terms of the agreement, we are required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitment of 20,000 Bbls per day over a term ending in December 2028. The aggregate financial commitment fee over the remaining term was $74.9 million as of December 31, 2023. We have not and do not expect to incur any deficiency payments.

Minimum Volume Agreement - Gas and Other. We are party to a gas gathering and processing agreement (the "Gathering Agreement") with a third-party midstream provider over a term ending in December 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 NGL 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 fee over the remaining term was $79.0 million as of December 31, 2023, which fluctuates with commodity prices as this is a value-based percentage of proceeds sales contract. During the year ended December 31, 2023, we recorded $5.6 million in other operating expense in the accompanying statements of operations based on volume deficiencies relative to the minimum volume commitment. Based on current projections, we may incur approximately $20.6 million of shortfall payments under the Gathering Agreement during the remaining term of approximately six years; however, we are actively engaging alternative strategies to reduce any potential contract deficiencies incurred in future periods.

Additionally, we are 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. Our share of these commitments requires an incremental 51.5 and 20.6 million cubic feet of natural gas ("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. We may be required to pay a shortfall fee for any incremental volume deficiencies under these commitments. These contractual obligations can be reduced by our 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 was zero as of December 31, 2023. We have not and do not expect to incur any deficiency payments.

We are also party to additional individually immaterial agreements that require us to pay a fee associated with the minimum volumes over various terms ending in December 2025, regardless of the amount delivered. The aggregate financial commitment fee over the remaining term for these contracts was $5.8 million as of December 31, 2023.

The minimum annual payments under these agreements for the next five years as of December 31, 2023 are presented below (in thousands):

	Firm Transportation	Minimum Volume[(1)]
2024	$ 18,932	$ 29,583
2025	6,501	30,952
2026	—	28,774
2027	—	28,720
2028 and thereafter	—	41,626
Total	$ 25,433	$ 159,655

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

Other commitments. We are party to a drilling commitment agreement with a third-party midstream provider such that we are 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 we 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 us and our affiliates. As of the date of filing, we cannot reasonably estimate how much, if any, damages will be paid.

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

Legal Proceedings

From time to time, we are involved in various legal proceedings that arise in the ordinary course of our business. We assess these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in our 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, we 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. We regularly review contingencies to determine the adequacy of our accruals and related disclosures.

As of the filing date of this report, there were no probable, material pending, or overtly threatened legal actions against us of which we are aware.

NOTE 7 - STOCK-BASED COMPENSATION

Long Term Incentive Plans

In April 2017, we 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, we 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, in conjunction with our merger with Extraction Oil & Gas, Inc. ("Extraction") in November 2021, we assumed Extraction's 2021 Long Term Incentive Plan (the "Extraction Equity Plan"), which reserved 3,305,080 shares of common stock now issuable by us. The 2017 LTIP, 2021 LTIP, and Extraction Equity Plan are collectively referred to herein as the "LTIP".

We record 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 in the accompanying statements of operations. The following table outlines the compensation expense recorded by type of award (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Restricted and deferred stock units	$ 19,502	$ 19,401	$ 11,895
Performance stock units	15,429	11,966	3,663
Total stock-based compensation	$ 34,931	$ 31,367	$ 15,558

As of December 31, 2023, 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	$ 37,446	2026
Performance stock units	23,730	2025
Total unrecognized stock-based compensation	$ 61,176	

Restricted Stock Units and Deferred Stock Units

We grant time-based Restricted Stock Units ("RSUs") to our officers, executives, and employees and time-based Deferred Stock Units ("DSUs") to our non-employee directors as part of our LTIP. Each RSU and DSU represents a right to receive one share of our common stock after the RSU or DSU vests and is settled as described below. RSUs generally vest ratably either over a one, two, or three-year service period on each anniversary following the grant date. Each RSU is entitled to a dividend equivalent right to receive, upon settlement, a cash payment based on the regular cash dividends that would have been paid on a share of our common stock during the period between the grant date and the date the RSUs vest and are settled. Accrued but unpaid dividend equivalents are recognized as a liability on the accompanying balance sheets, until the recipients receive the dividend equivalents upon vesting and settlement. DSUs generally vest over a one-year period following the grant date. DSUs are settled in shares of our common stock upon the non-employee director's separation of service from the Board of Directors (the "Board"). Each DSU is entitled to a dividend equivalent right to receive a cash payment based on the regular cash dividends that would have been paid on a share of our common stock. All amounts payable as a result of such dividend equivalent right are paid (1) with respect to vested DSUs, at the same time dividends are paid to our stockholders and (2) with respect to unvested DSUs, when such underlying DSUs vest. Accrued but unpaid dividend equivalents in respect of unvested DSUs are recognized as a liability on the accompanying balance sheets, until the recipients receive the dividend equivalents upon vesting. The grant-date fair value of RSUs and DSUs is equal to the closing price of our 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, 2023 is presented below:

	RSUs and DSUs	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	675,898	$ 50.27
Granted	607,987	72.10
Vested	(368,062)	47.46
Forfeited	(60,196)	60.05
Non-vested, end of year	855,627	$ 66.31

The aggregate grant-date fair value of the RSUs and DSUs granted under the LTIP during the year ended December 31, 2023 was $43.8 million.

Performance Stock Units

We grant market-based performance stock units ("PSUs") to our officers and certain executives as part of our LTIP. The number of shares of our common stock issued to settle PSUs ranges from zero to 225% (or, for PSUs granted prior to fiscal year 2023, 200%) of the number of PSUs granted and is determined based on performance achievement against certain market-based criteria over a three-year performance period. PSUs generally vest on December 31 of the year preceding the third anniversary of the date of grant and settle in January of the following year. Each PSU is entitled to a dividend equivalent right to receive, upon settlement, a cash payment based on the regular cash dividends that would have been paid on a share of our common stock during the period between the grant date and the date the PSUs vest. Accrued but unpaid dividend equivalents are recognized as a liability on the accompanying balance sheets, until the recipients receive the dividend equivalents upon vesting and settlement.

Performance achievement is determined based on either, or a combination of, (1) our annualized absolute total stockholder return ("TSR") or (2) for certain PSUs granted prior to fiscal year 2023, our absolute TSR relative to that of a defined peer group. Absolute TSR is determined based upon the performance of our common stock over the performance period relative to the price of our common stock at the grant date. For awards with a relative TSR component, our absolute TSR is compared with the absolute TSRs of a group of peer companies over the performance period. The absolute TSR for us 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 grant-date fair value of the PSUs was estimated using a Monte Carlo valuation model. The Monte Carlo valuation model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Significant assumptions used in this valuation include our expected volatility as well as the volatilities for each of our peers and an interpolated risk-free interest rate based on U.S. Treasury yields with maturities consistent with the performance period.

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,		
	2023	2022	2021
Expected term (in years)	3.0	3.2	2.2 to 3.0
Risk-free interest rate	3.6% to 5.0%	1.8% to 3.2%	0.3% to 0.6%
Expected daily volatility	3.1% to 3.7%	4.0% to 4.7%	3.8% to 4.7%

A summary of the status and activity of non-vested PSUs for the year ended December 31, 2023 is presented below:

	PSUs [(1)]	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	345,999	$ 77.42
Granted	290,496	104.11
Vested	(89,901)	78.49
Forfeited	(73,759)	87.49
Expired	(242)	18.26
Non-vested, end of year	472,593	$ 92.08

(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 our common stock issued may vary depending on the performance multiplier, which ranges from zero to 225% (or, for PSUs granted prior to fiscal year 2023, 200%), depending on the level of satisfaction of the performance condition.

The aggregate grant-date fair value of the PSUs granted under the LTIP during the year ended December 31, 2023 was $30.2 million. The performance period for PSUs granted in 2021 ended on December 31, 2023. These PSUs are expected to be released during the first quarter of 2024 with a performance achievement of 142%.

Stock Options

The LTIP allows for the issuance of stock options to our 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 our 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 and activity of stock options that are outstanding and exercisable for the year ended December 31, 2023 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	15,170	$ 34.36		
Exercised	(13,928)	34.36		
Forfeited	(111)	34.36		
Outstanding, end of year	1,131	$ 34.36	3.3	$ 38

The aggregate intrinsic value of options exercised during the year ended December 31, 2023 was $0.5 million.

NOTE 8 - FAIR VALUE MEASUREMENTS

We follow authoritative accounting guidance for measuring the fair value of assets and liabilities in our consolidated 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

We classify financial and non-financial assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy.

Derivatives

We use Level 2 inputs to measure the fair value of crude oil and natural gas commodity price derivatives. The fair value of our 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 us and our 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 our derivative instruments.

The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2023 and 2022 and their classification within the fair value hierarchy (in thousands):

	As of December 31, 2023		
	Level 1	Level 2	Level 3
Derivative assets	$ —	$ 43,425	$ —
Derivative liabilities	$ —	$ 18,096	$ —

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

Long-Term Debt

The 2026 Senior Notes, 2028 Senior Notes, 2030 Senior Notes, and 2031 Senior Notes are recorded at cost, net of any unamortized discount or deferred financing costs. As of December 31, 2023, the fair value of the 2026, 2028, 2030 and 2031 Senior Notes were $389.0 million, $1.41 billion, $1.06 billion and $1.43 billion, respectively. These fair values are based on quoted market prices, and as such, are designated as Level 1 within the fair value hierarchy. The recorded value of the Credit Facility, if any, 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

Warrants issued are indexed to our common stock and are required to be net share settled via a cashless exercise. Accordingly, they are classified as equity instruments. Our share price traded below the exercise price of the warrants and therefore were not exercisable during the years ended December 31, 2023 and 2022.

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 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 crude 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. The most significant fair value determinations for non-financial assets and liabilities are related to crude oil and gas properties acquired. Please refer to *Note 2 - Acquisitions and Divestitures* for additional information. During the years ended December 31, 2023, 2022, and 2021, we recorded no impairments of proved properties and incurred zero, $18.0 million, and $57.3 million, respectively, of abandonment and impairment of unproved properties. Please refer to *Note 1 - Summary of Significant Accounting Policies* for information on our policies for determining fair value of proved and unproved properties and related impairment expense.

NOTE 9 - DERIVATIVES

We periodically enter into commodity derivative contracts to mitigate a portion of our exposure to potentially adverse market changes in commodity prices for our expected future crude oil and natural gas production and the associated impact on cash flows. Our commodity derivative contracts consist of swaps, collars, basis protection swaps, and puts. As of December 31, 2023, all derivative counterparties were members of the Credit Facility lender group and all commodity derivative contracts are entered into for other-than-trading purposes. We do not designate our 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, we receive 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, we pay 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, we pay the difference between the index price and the ceiling price. When the index price is below the floor price at the time of settlement, we receive 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, we receive 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, we receive 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.

A put arrangement gives us the right to sell the underlying commodity at a strike price over the term of the contract. If the index price is higher than the strike price, no payment or receipt occurs. If the index price is lower than the strike price, we receive the difference between the index price and the strike price.

As of December 31, 2023, we had entered into the following commodity price derivative contracts:

	Contract Period				
	Q1 2024	Q2 2024	Q3 2024	Q4 2024	2025
Crude Oil Derivatives (volumes in Bbl/day and prices in $/Bbl)					
Swaps					
NYMEX WTI Volumes	19,727	15,491	14,036	10,997	1,238
Weighted-Average Contract Price	$ 72.75	$ 70.34	$ 70.34	$ 70.30	$ 72.23
Two-Way Collars					
NYMEX WTI Volumes	27,913	24,930	20,824	19,504	3,967
Weighted-Average Ceiling Price	$ 88.38	$ 85.90	$ 83.17	$ 81.97	$ 79.45
Weighted-Average Floor Price	$ 64.88	$ 64.98	$ 64.63	$ 64.77	$ 70.00
Three-Way Collars					
NYMEX WTI Volumes	573	—	—	—	—
Weighted-Average Ceiling Price	$ 56.25	$ —	$ —	$ —	$ —
Weighted-Average Floor Price	$ 45.00	$ —	$ —	$ —	$ —
Weighted-Average Sold Put Price	$ 35.00	$ —	$ —	$ —	$ —
Bought Puts					
NYMEX WTI Volumes	7,942	6,953	6,216	5,669	—
Weighted-Average Contract Price	$ 55.00	$ 55.00	$ 55.00	$ 55.00	$ —
Natural Gas Derivatives (volumes in MMBtu/day and prices in $/MMBtu)					
Swaps					
NYMEX HH Volumes	31,790	31,686	31,578	1,701	—
Weighted-Average Contract Price	$ 2.69	$ 2.68	$ 2.66	$ 4.23	$ —
Two-Way Collars					
NYMEX HH Volumes	736	1,732	1,668	—	—
Weighted-Average Ceiling Price	$ 3.16	$ 2.89	$ 3.16	$ —	$ —
Weighted-Average Floor Price	$ 2.50	$ 2.20	$ 2.50	$ —	$ —
Three-Way Collars					
NYMEX HH Volumes	1,166	55	—	—	—
Weighted-Average Ceiling Price	$ 3.50	$ 3.42	$ —	$ —	$ —
Weighted-Average Floor Price	$ 2.50	$ 2.50	$ —	$ —	$ —
Weighted-Average Sold Put Price	$ 2.00	$ 2.00	$ —	$ —	$ —
Basis Protection Swaps					
CIG-NYMEX HH Volumes	33,691	33,473	33,246	—	—
Weighted-Average Contract Price	$ (0.27)	$ (0.27)	$ (0.27)	$ —	$ —

Subsequent to December 31, 2023, we had entered into the following commodity price derivative contracts:

	Contract Period				
	Q1 2024	Q2 2024	Q3 2024	Q4 2024	2025
Crude Oil Derivatives (volumes in Bbl/day and prices in $/Bbl)					
Swaps					
NYMEX WTI Volumes	—	1,000	10,000	15,000	4,959
Weighted-Average Contract Price	$ —	$ 73.25	$ 72.29	$ 71.12	$ 71.48
Two-Way Collars					
NYMEX WTI Volumes	—	5,000	4,000	4,000	—
Weighted-Average Ceiling Price	$ —	$ 80.59	$ 78.68	$ 76.21	$ —
Weighted-Average Floor Price	$ —	$ 70.00	$ 70.00	$ 70.00	$ —

Derivative Assets and Liabilities Fair Value

Our 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 our 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 our commodity derivative contracts as of December 31, 2023 and 2022 (in thousands):

	As of December 31,	
	2023	2022
Derivative Assets:		
Commodity contracts - current	$ 35,192	$ 2,490
Commodity contracts - noncurrent	8,233	794
Total derivative assets	43,425	3,284
Amounts not offset in the accompanying balance sheets	(11,859)	—
Total derivative assets, net	$ 31,566	$ 3,284
Derivative Liabilities:		
Commodity contracts - current	$ (18,096)	$ (46,334)
Commodity contracts - long-term	—	(17,199)
Total derivative liabilities	(18,096)	(63,533)
Amounts not offset in the accompanying balance sheets	11,859	—
Total derivative liabilities, net	$ (6,237)	$ (63,533)

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,		
	2023	2022	2021
Derivative cash settlement gain (loss):			
Crude oil contracts	$ (59,543)	$ (346,419)	$ (215,057)
Gas contracts	(8,703)	(189,410)	(51,806)
NGL contracts	—	(40,973)	(9,051)
Total derivative cash settlement gain (loss)	(68,246)	(576,802)	(275,914)
Change in fair value gain	77,553	241,642	215,404
Total derivative gain (loss)	$ 9,307	$ (335,160)	$ (60,510)

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

We recognize an estimated liability for future costs associated with the abandonment of our 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 consolidated balance sheets. We deplete the amount added to proved properties and recognize 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 consolidated statements of cash flows.

Our 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 our asset retirement obligation is as follows (in thousands):

	Year Ended December 31,	
	2023	2022
Balance, beginning of year	$ 291,026	$ 225,315
Additional liabilities incurred with development activities and other	7,516	1,919
Additional liabilities incurred with acquisitions	40,373	1,112
Liabilities settled	(19,136)	(15,902)
Accretion expense	17,053	15,926
Revisions to estimate [1]	—	62,656
Balance, end of year	$ 336,832	$ 291,026
Current portion	31,116	25,557
Long-term portion	305,716	$ 265,469

[1] Revisions to estimates for the year ended December 31, 2022 were primarily a result of increases in our 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 we recognize 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 our common stock ranging from zero to 225% (or, for PSUs granted prior to fiscal year 2023, 200%) 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.

We have also issued stock options and warrants, which both represent the right to purchase our 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 earnings per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2023	2022	2021
Net income	$ 784,288	$ 1,248,080	$ 178,921
Basic earnings per common share	$ 9.09	$ 14.68	$ 4.82
Diluted earnings per common share	$ 9.02	$ 14.58	$ 4.74
Weighted-average shares outstanding - basic	86,240	85,005	37,155
Add: dilutive effect of stock awards	748	599	591
Weighted-average shares outstanding - diluted	86,988	85,604	37,746

There were 10,948, 20,699, and 178,051 unvested awards that were anti-dilutive for the years ended December 31, 2023, 2022, and 2021 respectively. The exercise price of our warrants was in excess of our stock price during the years ended December 31, 2023, 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,		
	2023	2022	2021
Current tax expense (benefit)			
Federal	$ (25,537)	$ 51,246	$ —
State	(4,460)	16,950	—
Total current tax expense (benefit)	(29,997)	68,196	—
Deferred tax expense			
Federal	238,426	289,578	62,212
State	6,737	47,924	10,646
Total deferred tax expense	245,163	337,502	72,858
Total income tax expense	$ 215,166	$ 405,698	$ 72,858

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,	
	2023	2022
Deferred tax liabilities:		
Oil and gas properties	$ 1,200,521	$ 868,612
Right-of-use assets	22,654	5,915
Total deferred tax liabilities	1,223,175	874,527
Deferred tax assets:		
Federal and state tax net operating loss carryforward	504,922	432,096
Interest expense carryforward	33,564	—
Asset retirement obligations	79,718	71,092
Commodity derivative contracts	7,251	37,293
Inventory	213	13,783
Stock-based compensation	7,327	5,974
Lease liability	22,866	6,067
Transaction costs	6,078	1,461
Other long-term assets	21,859	12,547
Total deferred tax assets	683,798	580,313
Less: Valuation allowance	25,404	25,404
Total deferred tax assets after valuation allowance	658,394	554,909
Deferred income tax liabilities, net	$ (564,781)	$ (319,618)

We had $2.1 billion and $1.8 billion of net operating loss carryovers for federal income tax purposes as of December 31, 2023 and 2022, respectively. Due to change of ownership provisions of Section 382 of the Internal Revenue 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 $1.5 billion have no expiration and can only be used to offset 80% of taxable income when utilized.

We assess the recoverability of our 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, we consider all available evidence (both positive and negative), including future reversals of temporary differences, tax-planning strategies, projected future taxable income, and results of operations. As a result of merger activity in 2021, we recorded a valuation allowance of $25.4 million, which continued to be recorded as of December 31, 2023 and 2022, 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 Internal Revenue Code. We 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 due to state income taxes and other changes outlined as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Federal statutory tax expense	$ 210,458	$ 347,293	$ 52,824
Increase (decrease) in tax resulting from:			
State tax expense, net of federal benefit	26,081	58,658	10,646
State tax rate change	(23,002)	—	—
Return to provision	(1,866)	19,975	27
Compensation of covered individuals	5,689	6,138	1,793
Stock-based compensation	(2,996)	(3,343)	(1,559)
Transaction costs	—	—	9,043
Bargain purchase gain	—	(2,852)	—
Tax credits	—	(1,405)	—
Change in valuation allowance	—	(19,302)	—
Other	802	536	84
Total income tax expense	$ 215,166	$ 405,698	$ 72,858

Acquisitions, including the Hibernia Acquisition and the Tap Rock Acquisition, divestitures, drilling activity, and the prices received for crude oil, natural gas, and NGL, impact the apportionment of taxable income to the states where we own crude oil and natural gas properties. As these factors change, our state income tax rate changes. This change, when applied to our total temporary differences, impacts the total state income tax (expense) benefit reported in the current year.

We had no unrecognized tax benefits as of December 31, 2023, 2022, and 2021. As of December 31, 2023, the Company is subject to U.S. federal and state income tax examination for the years ended December 31, 2022, 2021, and 2020. Tax returns for years prior to 2020 may remain open with respect to net operating loss carryforwards that are utilized in a later year, as tax attributes from prior years can be adjusted during an audit of a later year.

In 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. We are 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

Our 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. The following table summarizes the asset classes of our operating leases (in thousands):

	As of December 31,	
	2023	2022
Operating Leases		
Field equipment[1]	$ 61,662	$ 15,131
Corporate leases	8,864	8,235
Vehicles	7,740	759
Total right-of-use asset	$ 78,266	$ 24,125
Field equipment[1]	$ 61,741	$ 15,131
Corporate leases	9,653	8,898
Vehicles	7,740	759
Total lease liability	$ 79,134	$ 24,788
Finance Leases		
Right of use asset - field equipment	$ 16,340	$ —
Lease liability - field equipment	$ 16,404	$ —

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

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

	Year Ended December 31,		
	2023	2022	2021
Operating lease cost	$ 32,769	$ 21,050	$ 15,449
Finance lease cost			
Amortization of ROU assets	1,275	—	3
Interest on lease liabilities	442	—	1
Short-term lease cost[1]	79,405	55,059	3,662
Total lease cost[2]	$ 113,891	$ 76,109	$ 19,115

(1) 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.
(2) 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, 2023, 2022, and 2021.

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. Our 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.

We recognize 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.

Our weighted-average remaining lease terms and discount rates as of December 31, 2023 are as follows:

	Operating Leases	Finance Leases
Weighted-average lease term (years)	2.1	6.1
Weighted-average discount rate	6.4%	6.3%

Future commitments by year for our leases with a lease term of greater than one year as of December 31, 2023 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	Finance Leases
2024	$ 45,524	$ 4,210
2025	27,392	4,277
2026	7,576	4,020
2027	2,833	3,684
2028	1,019	1,350
Thereafter	—	1,461
Total lease payments	84,344	19,002
Less: Imputed interest	(5,210)	(2,598)
Total lease liability	$ 79,134	$ 16,404

NOTE 14 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2023	2022	2021
Supplemental cash flow information:			
Cash (paid) refunded for income taxes	$ 50,049	$ (97,800)	$ (14,000)
Cash paid for interest	(37,112)	(28,528)	(1,829)
Supplemental non-cash investing and financing activities:			
Investing activities for property additions related to acquisitions of businesses	1,049,129	—	4,911,186
Issuance of common stock for acquisition of businesses	990,204	—	3,481,312
Changes in working capital related to capital expenditures	(12,349)	(7,679)	(128,977)
Supplemental cash flow information related to leases:			
Cash paid for amounts included in the measurement of lease liabilities - operating cash flows from operating leases	32,563	19,541	14,284
Right-of-use assets obtained in exchange for new operating lease obligations	85,521	4,874	25,469
Right-of-use assets obtained in exchange for new finance lease obligations	17,614	—	—

NOTE 15 - STOCKHOLDERS' EQUITY

Share Repurchases

On January 24, 2023, we 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 our common stock at a price of $61.00 per share for a total purchase price of approximately $300.0 million. The purchase closed on January 27, 2023 and was funded from our cash on hand. The shares repurchased were immediately retired.

In February 2023, we announced that the Board provided authorization for a stock repurchase program (the "stock repurchase program") pursuant to which we may, from time to time and through December 31, 2024, acquire shares of our common stock in the open market, in privately negotiated transactions, or through block trades, derivative transactions, or purchases made in accordance with the Rule 10b5-1 of the Exchange Act in an amount not to exceed $1.0 billion, exclusive of any fees, commissions, or other expenses related to such repurchases. In June 2023, commensurate with the announcement of the Hibernia Acquisition and the Tap Rock Acquisition, the Board reduced the amount of stock authorized for repurchase by us under the stock repurchase program from $1.0 billion to $500.0 million. The stock repurchase program does not require any specific number of shares to be acquired and can be modified or discontinued by the Board at any time. As of December 31, 2023, we repurchased approximately 312,800 shares under the program at a weighted average price of $64.55 per share for a total cost of $20.3 million.

We record share repurchases at cost, which includes incremental direct transaction costs, as a reduction to stockholder's equity. As part of the incremental direct transaction costs and subject to netting against the fair value of stock issuances, we record a 1% excise tax with the corresponding liability recorded within accounts payable and accrued expenses on the accompanying balance sheets. Any excess of cost over the par value is charged to additional paid-in-capital on a pro-rata basis, with any remaining cost charged to retained earnings.

On February 27, 2024, we entered into a privately-negotiated share purchase agreement with NGP Tap Rock Holdings, LLC and certain of its affiliates ("NGP") for the purchase of approximately 876,200 shares of our common stock at a price of $64.54 per share for a total purchase price of approximately $56.5 million. The purchase is expected to close in early March 2024 and will be funded from our cash on hand. Following the closing of the agreement, NGP will no longer be a stockholder of Civitas.

Dividends

As approved by the Board, cash dividends are paid quarterly and consist of a base and variable component. Variable cash dividends are 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.

The following table summarizes the dividends declared for the years ended December 31, 2023, 2022, and 2021 (in thousands, except per share amounts):

	Year Ended December 31,		
	2023	**2022**	**2021**
Base dividend	$ 2.00	$ 1.89	$ 1.16
Variable dividend	5.60	4.40	—
Total dividend	$ 7.60	$ 6.29	$ 1.16
Total dividend (in thousands)	$ 668,669	$ 541,254	$ 61,704

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.

NOTE 16 - DISCLOSURES ABOUT CRUDE OIL AND NATURAL GAS PRODUCING ACTIVITIES (UNAUDITED)

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

	Year Ended December 31,		
	2023	**2022**	**2021**
Acquisition(1)	$ 5,039,610	$ 437,100	$ 4,861,619
Development(2)(3)	1,386,371	1,044,392	315,746
Exploration	2,178	6,981	7,937
Total	$ 6,428,159	$ 1,488,473	$ 5,185,302

(1) Acquisition costs for unproved properties for the years ended December 31, 2023, 2022, and 2021 were $414.7 million, $16.8 million, and $648.0 million, respectively. There were $4.6 billion, $420.3 million, and $4.2 billion in acquisition costs for proved properties for the years ended December 31, 2023, 2022, and 2021, respectively.

(2) Development costs include workover costs of $14.1 million, $8.6 million, and $2.2 million charged to lease operating expense for the years ended December 31, 2023, 2022, and 2021, respectively.

(3) Includes amounts relating to asset retirement obligations of $7.5 million, $64.7 million, and $13.8 million for the years ended December 31, 2023, 2022, and 2021, respectively.

Suspended Well Costs

We did not incur any exploratory well costs during the years ended December 31, 2023, 2022, and 2021.

Reserves

The proved reserve estimates at December 31, 2023, 2022, and 2021 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 our crude oil, natural gas, and NGL reserves are attributable to properties within the United States. A summary of our changes in quantities of proved crude oil, natural gas, and NGL reserves for the years ended December 31, 2023, 2022, and 2021 are as follows:

	Crude Oil (MBbl)	Natural Gas (MMcf)	NGL (MBbl)	Total (MBoe)
Proved reserves-December 31, 2020	52,793	235,728	26,111	118,192
Extensions, discoveries, and other additions	19	103	—	36
Production	(4,523)	(13,852)	(1,763)	(8,595)
Removed from capital program	(12,249)	(43,918)	(4,485)	(24,054)
Acquisition of reserves	114,379	767,504	89,797	332,093
Revisions to previous estimates(1)	(6,840)	(57,066)	(3,632)	(19,983)
Proved reserves-December 31, 2021	143,579	888,499	106,028	397,690
Extensions, discoveries, and other additions	12,408	51,358	6,936	27,904
Production	(27,651)	(112,478)	(15,666)	(62,063)
Removed from capital program	(105)	(459)	(46)	(228)
Acquisition of reserves	17,479	31,872	4,478	27,269
Revisions to previous estimates(1)	6,892	8,708	17,104	25,447
Proved reserves-December 31, 2022	152,602	867,500	118,834	416,019
Extensions, discoveries, and other additions	12,598	31,174	3,719	21,513
Production	(36,726)	(133,821)	(18,400)	(77,430)
Divestiture of reserves(1)	(830)	(3,582)	(514)	(1,940)
Removed from capital program	(2,301)	(7,812)	(1,155)	(4,758)
Acquisition of reserves	151,717	635,710	114,708	372,377
Revisions to previous estimates(1)	(4,255)	(68,867)	(12,249)	(27,982)
Proved reserves-December 31, 2023	272,805	1,320,302	204,943	697,799
Proved developed reserves:				
December 31, 2021	104,078	748,762	88,967	317,839
December 31, 2022	117,768	750,793	102,004	344,904
December 31, 2023	199,585	1,077,221	162,117	541,239
Proved undeveloped reserves:				
December 31, 2021	39,501	139,737	17,061	79,851
December 31, 2022	34,834	116,707	16,830	71,115
December 31, 2023	73,220	243,081	42,826	156,560

(1) Items may not recalculate due to rounding.

During the years ended December 31, 2023, 2022, and 2021, horizontal development resulted in extensions, discoveries, and other additions of 21.5 MMBoe, 27.9 MMBoe, and nominal MMBoe, respectively.

During the years ended December 31, 2023, 2022, and 2021, proved undeveloped reserves were reduced by 4.8 MMBoe, 0.2 MMBoe, and 24.1 MMBoe respectively, primarily due to the removal of proved undeveloped locations from our five-year drilling program.

As of December 31, 2023, we revised our proved reserves downward by 28.0 MMBoe. Price-related revisions of 11.1 MMBoe resulted from the decrease to SEC prices of $15.45 to $78.22 per Bbl WTI for crude oil and $3.72 to $2.64 per MMBtu HH for natural gas. Additionally we had negative revision of (i) 11.0 MMBoe from non-producing wells that have been plugged and abandoned or are planned to be plugged and abandoned, (ii) negative revisions of 14.2 MMBoe in updates to costs associated with production, and (iii) updates to well performance that resulted in negative revisions of 0.9 MMBoe. The negative revisions were partially offset by 9.2 MMBoe from increases in interests and positive volume changes in natural gas shrinks and NGL yields.

As of December 31, 2022, we revised 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 crude 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, we revised 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.

The standardized measure of discounted future net cash flows relating to proved oil and 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, producing, and plugging and abandoning the proved 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 reserves. Future income tax expenses give effect to permanent differences, tax credits, and loss carryforwards relating to the proved 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 our crude oil and natural gas properties.

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

	Year Ended December 31,		
	2023	2022	2021
Future cash flows	$ 27,947,743	$ 23,225,188	$ 14,401,814
Future production costs	(11,038,268)	(6,490,522)	(5,054,695)
Future development costs	(2,366,582)	(1,337,494)	(1,107,576)
Future income tax expense	(1,605,756)	(2,870,178)	(1,465,949)
Future net cash flows	12,937,137	12,526,994	6,773,594
10% annual discount for estimated timing of cash flows	(4,667,858)	(4,599,504)	(2,361,490)
Standardized measure of discounted future net cash flows	$ 8,269,279	$ 7,927,490	$ 4,412,104

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 reserves are as follows (in thousands):

	Year Ended December 31,		
	2023	2022	2021
Beginning of period	$ 7,927,490	$ 4,412,104	$ 437,054
Crude oil, natural gas, and NGL sales, net of production costs	(2,558,095)	(2,980,527)	(773,711)
Net changes in prices and production costs	(4,385,615)	5,016,678	874,155
Net changes in extensions, discoveries, and other additions	363,594	638,537	855
Development costs incurred	447,181	411,138	108,113
Changes in estimated development cost	(39,386)	(87,466)	106,788
Acquisition of reserves	5,199,814	627,833	4,484,125
Divestiture of reserves	(32,483)	—	—
Revisions of previous quantity estimates	(529,185)	619,800	(84,126)
Net change in income taxes	796,068	(991,734)	(915,053)
Accretion of discount	983,428	532,716	43,705
Changes in production rates and other	96,468	(271,589)	130,199
End of period	$ 8,269,279	$ 7,927,490	$ 4,412,104

Reserve estimates are based on an unweighted 12-month arithmetic average of first-day-of-the-month prices inclusive of adjustments for quality and location as of December 31, 2023, 2022, and 2021, as required by the SEC.

	Year Ended December 31,		
	2023	2022	2021
Crude Oil (per Bbl)	$ 75.57	$ 90.28	$ 61.60
Gas (per Mcf)	$ 2.03	$ 5.54	$ 2.60
NGL (per Bbl)	$ 22.69	$ 39.05	$ 30.60

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, 2023. 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 our 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, 2023, 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. Our 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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Our internal control over financial reporting is a process designed under the supervision of our 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, 2023, 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 we maintained effective internal control over financial reporting as of December 31, 2023. Management's evaluation of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the Hibernia Acquisition and Tap Rock Acquisition, as defined herein, on August 2, 2023. The total revenues of Hibernia and Tap Rock represent approximately 9% and 12% of the related consolidated financial statement amounts for the year ended December 31, 2023.

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, 2023, which is included within this section.

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, 2023 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, 2023, 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, 2023, 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, 2023, of the Company and our report dated February 27, 2024, expressed an unqualified opinion on those financial statements.

As described in Management’s Assessment of Internal Control Over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Hibernia Energy III, LLC and Hibernia Energy III-B, LLC (“Hibernia”) and Tap Rock AcquisitionCo, LLC, Tap Rock Resources II, LLC, and Tap Rock NM10 Holdings, LLC (“Tap Rock”), which were acquired on August 2, 2023. The total revenues of Hibernia and Tap Rock represent approximately 9% and 12%, respectively, of the related consolidated financial statement amounts for the year ended December 31, 2023. Accordingly, our audit did not include the internal control over financial reporting at Hibernia or Tap Rock.

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 27, 2024

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, 2023.

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, 2023.

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, 2023.

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, 2023.

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, 2023.

PART IV

Item 15. ***Exhibits and 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).
2.6	Membership Interest Purchase Agreement, dated as of June 19, 2023, by and among Hibernia Energy III Holdings, LLC and Hibernia Energy III-B Holdings, LLC, as sellers, and Civitas Resources, Inc., as purchaser (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on June 20, 2023).
2.7	Membership Interest Purchase Agreement, dated as of June 19, 2023, by and among Tap Rock Resources Legacy, LLC, Tap Rock Resources Intermediate, LLC, Tap Rock Resources II Legacy, LLC, Tap Rock Resources II Intermediate, LLC, Tap Rock NM10 Legacy Holdings, LLC and Tap Rock NM10 Holdings Intermediate, LLC, as sellers, solely in its capacity as Sellers' Representative, Tap Rock Resources Legacy, LLC, solely for the limited purposes set forth therein, Tap Rock Resources, LLC, and Civitas Resources, Inc., as purchaser (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on June 20, 2023).
2.8	First Amendment to Membership Interest Purchase Agreement, dated August 1, 2023, by and among Tap Rock Resources Legacy, LLC, Tap Rock Resources Intermediate, LLC, Tap Rock Resources II Legacy, LLC, Tap Rock Resources II Intermediate, LLC, Tap Rock NM10 Legacy Holdings, LLC and Tap Rock NM10 Holdings Intermediate, LLC, as sellers, Tap Rock Resources Legacy, LLC, solely for the limited purposes set forth therein, Tap Rock Resources, LLC, and Tap Rock Resources Legacy, LLC and Civitas Resources, Inc., as purchaser (incorporated by reference to Exhibit 2.3 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on November 7, 2023).
2.9	Second Amendment to Membership Interest Purchase Agreement, dated October 31, 2023, by and among Tap Rock Resources Legacy, LLC, Tap Rock Resources Intermediate, LLC, Tap Rock Resources II Legacy, LLC, Tap Rock Resources II Intermediate, LLC, Tap Rock NM10 Legacy Holdings, LLC and Tap Rock NM10 Holdings Intermediate, LLC, as sellers, Tap Rock Resources Legacy, LLC, solely for the limited purposes set forth therein, Tap Rock Resources, LLC, and Tap Rock Resources Legacy, LLC and Civitas Resources, Inc., as purchaser (incorporated by reference to Exhibit 2.4 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on November 7, 2023).

2.10†	Third Amendment to Membership Interest Purchase Agreement, dated December 22, 2023, by and among Tap Rock Resources Legacy, LLC, Tap Rock Resources Intermediate, LLC, Tap Rock Resources II Legacy, LLC, Tap Rock Resources II Intermediate, LLC, Tap Rock NM10 Legacy Holdings, LLC and Tap Rock NM10 Holdings Intermediate, LLC, as sellers, Tap Rock Resources Legacy, LLC, solely for the limited purposes set forth therein, Tap Rock Resources, LLC, and Tap Rock Resources Legacy, LLC and Civitas Resources, Inc., as purchaser.
2.11	Purchase and Sale Agreement, dated as of October 3, 2023, by and among Vencer Energy, LLC, as seller, and Civitas Resources, Inc., as buyer (incorporated by reference to Exhibit 2.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on October 4, 2023).
3.1	Fourth Amended and Restated Certificate of Incorporation of Civitas Resources, Inc. (incorporated by reference to Exhibit 3.1 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on August 2, 2023).
3.2	Seventh Amended and Restated Bylaws of Civitas Resources, Inc. (incorporated by reference to Exhibit 3.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on June 5, 2023).
4.1	Description of Capital Stock.
4.2	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).
4.3	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).
4.4	Third Supplemental Indenture, dated August 2, 2023, by and among Civitas Resources, Inc., as issuer, the guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on November 7, 2023).
4.5	Indenture, dated June 29, 2023, by and among Civitas Resources, Inc., as issuer, the guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on June 29, 2023).
4.6	First Supplemental Indenture, dated August 2, 2023, by and among Civitas Resources, Inc., as issuer, the guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on November 7, 2023).
4.7	Indenture, dated June 29, 2023, by and among Civitas Resources, Inc., as issuer, the guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on June 29, 2023).
4.8	First Supplemental Indenture, dated August 2, 2023, by and among Civitas Resources, Inc., as issuer, the guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.2 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on November 7, 2023).
4.9	Indenture, dated October 17, 2023, by and among Civitas Resources, Inc., as issuer, the guarantors party thereto and Computershare Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on October 18, 2023).
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	Registration Rights Agreement, dated as of August 2, 2023, by and between Civitas Resources, Inc. and the persons identified on Schedule I thereto (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on August 2, 2023).
10.7	Registration Rights Agreement, dated as of January 2, 2024, by and between Civitas Resources, Inc. and the persons identified on Schedule I thereto (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on January 2, 2024).
10.8*	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).
10.9*	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).
10.10*	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).
10.11*	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),
10.12*	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).
10.13*	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).
10.14*	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).
10.15*	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).
10.16*	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).
10.17*	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).
10.18*	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).
10.19*	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).
10.20*	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).
10.21*	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).
10.22*	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 (incorporated by reference to Exhibit 10.24 to Civitas Resources, Inc.'s Annual Report on Form 10-K filed on February 22, 2023).
10.23*	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).
10.24*	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).

10.25*	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).
10.26*	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).
10.27*	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).
10.28*	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)
10.29	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).
10.30	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).
10.31	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).
10.32	Third Amendment to Amended and Restated Credit Agreement, dated June 23, 2023, 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 June 26, 2023).
10.33	Fourth Amendment to Amended and Restated Credit Agreement, dated August 2, 2023, 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 August 2, 2023).
10.34	Fifth Amendment to Amended and Restated Credit Agreement, dated October 6, 2023, 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 October 10, 2023).
10.35	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).
10.36	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).
10.37	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).
10.38*	Form of Officer Restricted Stock Unit Agreement under the Civitas Resources, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q, filed on May 3, 2023).
10.39*	Form of Officer Performance Stock Unit Agreement under the Civitas Resources, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q, filed on May 3, 2023).
10.40*	Form of Officer Restricted Stock Unit Agreement under the Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q, filed on May 3, 2023).
10.41*	Form of Officer Performance Stock Unit Agreement under the Extraction Oil & Gas, 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 3, 2023).

10.42*	Employment Letter, dated as of April 5, 2023, by and between Civitas Resources, Inc. and T. Hodge Walker (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on April 6, 2023).
10.43*	Severance and Release Agreement, dated as of May 31, 2023, by and between Civitas Resources, Inc. and Matthew R. Owens (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on June 5, 2023).
10.44*	Employment Letter, dated as of November 28, 2023, by and between Civitas Resources, Inc. and Kayla D. Baird (incorporated by reference to Exhibit 10.1 to Civitas Resources, Inc.'s Current Report on Form 8-K filed on November 29, 2023).
10.45*†	Employment Letter, dated as of August 3, 2023, by and between Civitas Resources, Inc. and Jeffrey S. Kelly.
10.46*†	Civitas Resources, Inc. Amended & Restated Independent Director Compensation Program.
10.47*†	Form of Director Restricted Stock Unit Agreement under the Civitas Resources, Inc. 2021 Long Term Incentive Plan.
10.48*†	Form of Director Restricted Stock Unit Agreement under the Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan.
10.49*†	Form of Employee Restrictive Covenants, Proprietary Information and Inventions Agreement.
10.50*†	Form of Cash Award Agreement under the Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan.
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)
97†	Civitas Resources, Inc. Clawback Policy
99.1†	Report of Independent Petroleum Engineers, Ryder Scott Company, L.P., for reserves as of December 31, 2023
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)

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* Management Contract or Compensatory Plan or Arrangement

† Filed or furnished herewith

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

None.

SIGNATURES

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

			CIVITAS RESOURCES, INC.
Date:	February 27, 2024	By:	/s/ Chris Doyle
			Chris Doyle, *President, Chief Executive Officer, and Director* *(principal executive officer)*

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Chris Doyle, Marianella Foschi, Adrian Milton, and Kayla D. Baird 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 27, 2024

By: /s/ Chris Doyle

Chris Doyle,
President, Chief Executive Officer, and Director (principal executive officer)

By: /s/ Marianella Foschi

Marianella Foschi,
Chief Financial Officer and Treasurer (principal financial officer)

By: /s/ Kayla D. Baird

Kayla D. Baird,
Senior Vice President and Chief Accounting Officer (principal accounting officer)

By: /s/ Wouter van Kempen

Wouter van Kempen,
Chairman of the Board

By: /s/ Deborah Byers

Deborah Byers,
Director

By: /s/ Morris R. Clark

Morris R. Clark,
Director

By: /s/ Carrie M. Fox

Carrie M. Fox,
Director

By: /s/ Carrie L. Hudak

Carrie Hudak,
Director

By: /s/ James M. Trimble

James Trimble,
Director

By: /s/ Howard A. Willard, III

Howard A. Willard, III,
Director

By: /s/ Jeffrey E. Wojahn

Jeffrey E. Wojahn,
Director

Corporate Information

Board of Directors

Wouter van Kempen
Chairman of the Board

Deborah Byers
Director

Morris Clark
Director

Chris Doyle
Director, President and Chief Executive Officer

Carrie Fox
Director

Carrie Hudak
Director

James Trimble
Director

Howard Willard III
Director

Jeffrey Wojahn
Director

Executive Officers

Chris Doyle
Director, President and Chief Executive Officer

Hodge Walker
Chief Operating Officer

Marianella Foschi
Chief Financial Officer and Treasurer

Travis Counts
Chief Administrative Officer and Secretary

Jeff Kelly
Chief Transformation Officer

Kayla Baird
Senior Vice President and Chief Accounting Officer

Ji Rim
Senior Vice President, Environment, Health, Safety and Regulatory; Chief Sustainability Officer

Sam Blatt
Senior Vice President, Permian

Brad Johnson
Senior Vice President, Rockies

Brian Kuck
Senior Vice President, Business Development and Reserves

Adrian Milton
Senior Vice President, General Counsel and Assistant Corporate Secretary

Shareholder Information

Common Stock

Listed: New York Stock Exchange
Ticker Symbol: CIVI
civitasresources.com

Investor Relations Contact

Brad Whitmarsh
Vice President of Investor Relations

ir@civiresources.com

Independent Auditors

Deloitte & Touche LLP
Denver, Colorado

Transfer Agent

Broadridge Corporate Issuer Solutions, Inc.
P.O. Box 1342
Brentwood, NY 11717

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1-866-321-8022

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1-720-378-5956

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