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, 2024

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 28, 2024, based upon the closing price of $69.00 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $6.8 billion. Excludes approximately 0.2 million shares of the registrant's common stock held by executive officers and directors. The registrant has concluded that no shares of its common stock were held by stockholders who were affiliates of the registrant.

Number of shares of registrant's common stock outstanding as of February 21, 2025: 93,017,260

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, 2024, as incorporated by reference into Part III of this report for the year ended December 31, 2024.

CIVITAS RESOURCES, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2024

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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 (the “Securities Act”), 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;
- crude oil, natural gas, and natural gas liquids prices and factors affecting the volatility of such prices;
- 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;
- 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 crude 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 stock 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 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;
- 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 crude oil and natural gas reserves;
- changes in local, state, and federal laws, regulations or policies that may affect our business or our industry (such as the effects of tax law changes, and changes in environmental, health, and safety regulation and regulations addressing climate change, and trade policy and tariffs);
- 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 crude oil and natural 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;
- pandemics and other public health epidemics;
- political conditions in or affecting other producing countries, including conflicts or hostilities in or relating to the Middle East, South America, and Russia (including the current events involving Russia and Ukraine), and other sustained military campaigns or acts of terrorism or sabotage and the effects therefrom; 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 depicts the subsurface strata in three dimensions. 3-D seismic data typically provides 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.

"Carbon neutral" or "Carbon neutrality." Carbon neutral and carbon neutrality means that any greenhouse gas emissions derived from a defined scope of the Company's activities are balanced by an equivalent amount being removed, including through the use of certified carbon credits and renewable energy certificates.

"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 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 geoscientists 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 vertical wells is 40 acres for oil wells and 640 acres for gas wells. Typical spacing for horizontal 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."

"Waha." Index commonly used for natural gas in the Permian Basin.

"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.

SUMMARY OF RISK FACTORS

The following is a summary of the principal risks that could materially adversely affect our business, financial condition and results of operations. Refer to Risk Factors under Part I, Item 1A of this Annual Report on Form 10-K for a more detailed description of each risk factor.

Risks Related to Commodity Prices

- 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.
- 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.

Risks Related to Our Reserves, Leases, and Drilling Locations

- 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 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.

Risks Related to Our Business and 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.
- We intend to pursue the further development of our properties through horizontal drilling and completion, which can be operationally challenging and costly.
- 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 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.

Risks Related to Our Derivative Activities, Debt Agreements, and Access to Capital

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

Risks Related to Legislative and Regulatory Initiatives

- 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.
- 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.
- 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 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.
- 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.

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.
- Our ability to pay dividends to or repurchase shares of common stock from 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.
- Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such acquisition or merger may be in our stockholders’ best interests.
- Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders’ ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees.

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.” 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 in the DJ Basin in Colorado 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, and enhanced recovery potential.

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

Our Business Strategies

Our primary objective is to maximize stockholder returns by responsibly developing our crude 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 significant 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 Adjusted Free Cash Flow, across two premier basins. We pursue value-enhancing investments to sustain and increase our ability to deliver incremental returns to our stockholders. In 2023 and 2024, our assets generated $795.9 million and $1.3 billion, respectively, of Adjusted Free Cash Flow, a non-GAAP financial measure.

- ***Maintain a premier balance sheet.*** We place great importance on maintaining a strong balance sheet, focusing on cost control, and minimizing long-term commitments. These strategies are critical to managing risk and achieving success within fluctuating market conditions. Our assets provide significant strength to our balance sheet, with the DJ and Permian Basins having the lowest break-even points in the U.S.

- ***Return capital to our stockholders.*** We return capital to stockholders through a combination of fixed dividends, variable dividends, and/or stock repurchases. From the beginning of 2023 through the Company's fourth quarter of 2024 return of capital, we repurchased 12.5 million shares of our common stock for an aggregate purchase price of $747.4 million and paid $1.2 billion in base and variable dividends, totaling a combined return to stockholders of approximately 92% of our combined 2023 and 2024 Adjusted Free Cash Flow, a non-GAAP financial measure.

- ***Demonstrate ESG Leadership.*** We believe in the importance of building a sustainable company and have integrated Environmental, Social, and Governance (“ESG”) initiatives throughout our organization.

  Environment. We are committed to making meaningful progress on reducing the greenhouse gas (“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. In 2021, Civitas became Colorado’s first carbon neutral operator with respect to Scope 1 and Scope 2 GHG emissions. We are committed to achieving carbon neutrality on our Permian Basin assets by the end of 2025, successfully marking the execution of our mission to “disrupt energy for good” by minimizing environmental impacts through emissions reductions. Our commitment to achieving carbon neutrality is rooted in commonly accepted estimates of offset and emissions accounting, which is built on a foundation of emissions reporting, and in which we seek to further improve upon by transitioning to actual emissions measurements and other carbon projects that have a positive impact in the communities where we operate.

  Social. The safety of our communities, employees, and contractors is a top priority. We have developed, promoted and implemented best practices around safety and community impact; we continue to innovate and enhance those practices. Refer to our “*Human Capital”* included below for more discussion.

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

Refer to our Corporate Sustainability Report published on our website for additional 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.

Significant Developments in 2024

Diversify, Scale, and Extend Our Asset Base. On January 2, 2024, we completed the acquisition (the "Vencer Acquisition") of certain crude oil and natural gas assets from Vencer Energy, LLC ("Vencer"). The Vencer Acquisition included approximately 44,000 net acres in the Midland Basin, which is part of the larger Permian Basin, and certain related crude oil and natural gas assets with average production of approximately 49 MBoe per day as of January 2, 2024 in exchange for adjusted aggregate consideration of approximately $2.0 billion, consisting of approximately $1.0 billion in cash paid at the closing of the Vencer Acquisition, 7.2 million shares of our common stock issued at the closing of the Vencer Acquisition, and $550.0 million in cash to be paid on or before January 3, 2025, inclusive of customary post-closing adjustments. In 2024, we made two early payments totaling $75.0 million towards the deferred consideration. The remaining balance of $475.0 million was paid on January 3, 2025. The initial cash portion of the Vencer Acquisition was funded by cash on hand and the issuance of $1.0 billion in aggregate principal amount of our 2030 Senior Notes. Refer to "*Part II - Item 8. Financial Statements and Supplementary Data - Note 2 - Acquisitions and Divestitures*" and "*Part II - Item 8. Financial Statements and Supplementary Data - Note 5 - Debt*" for additional discussion. Additionally, we increased our overall footprint in both the DJ and Permian Basins through smaller-scale organic leasing activity, asset exchanges, an asset acquisition, and multiple farm-in agreements.

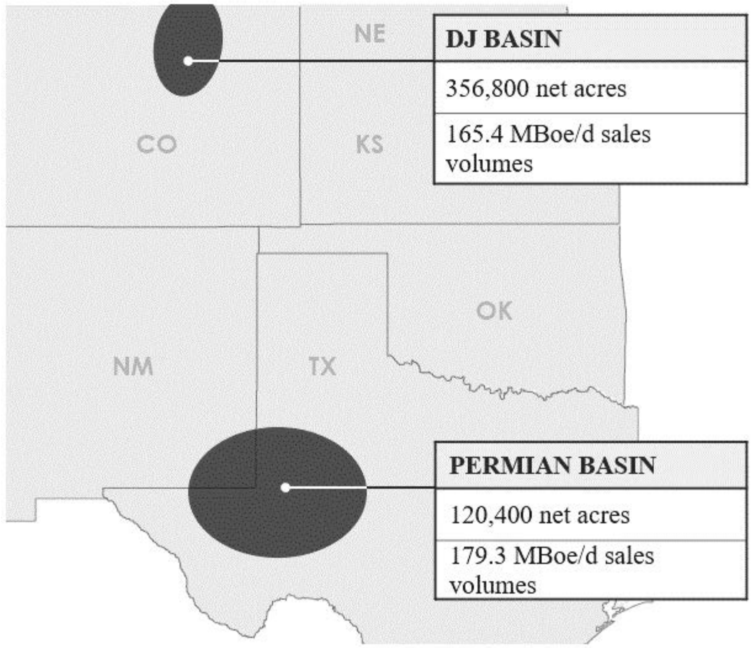
Capital Returns. We posted strong financial results, including net income of $838.7 million and cash flow from operating activities of $2.9 billion, underpinned by well performance from our high-return development projects. We invested a portion of our cash flow from operating activities into the development of our crude oil and natural gas properties, enabling us to return significant capital to our stockholders. During 2024, we paid $493.8 million through base and variable dividends and repurchased approximately 7.3 million shares of our common stock at an average price of $58.42 per share.

Enhanced Operational Performance. In 2024, our primary objective was to establish and operationalize our newly formed Permian Basin team from our 2023 and early 2024 acquisitions. Secondly, we continued to seek ways to maximize the value of our drilling and completion efforts in the DJ and Permian Basins. In the DJ Basin, we continued driving capital efficiencies through longer lateral development, including four-mile wells. In the Permian Basin, we dramatically reduced our drilling and completion cycle times and implemented simulfrac completion techniques. All of these actions have lowered costs per lateral foot. In addition, our teams delineated future development inventory in the Permian Basin with successful Wolfcamp D results. We regularly evaluate our operating results against those of other top operators in the area in an effort to benchmark our performance and adopt best practices compared to our peers.

Sustainability Performance. We advanced environmental, health, and safety objectives critical to our business operations, 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 have reached previously stated emissions intensity reduction targets in the DJ Basin earlier than projected due to the continued implementation of our comprehensive retrofit program of natural gas pneumatic devices. Aligned with our 2024 objective to operationalize our newly formed Permian Basin team, we established a new target of reducing our Scope 1 GHG emissions by 40% by 2030 from our 2023 EPA Subpart W baseline.

Our Operations

Our operations are concentrated in the DJ Basin and Permian Basin as described above. The following chart outlines our asset positions, net mineral acres, and average daily production volumes for the year ended December 31, 2024.



The following table summarizes estimated proved reserves and net sales volumes for the year ended December 31, 2024 for these areas:

	DJ Basin	Permian Basin	Total
Proved reserves			
Crude oil (MBbl)	137,857	167,504	305,361
Natural gas (MMcf)	746,826	792,692	1,539,518
NGL (MBbl)	91,314	144,462	235,776
Total proved reserves (MBoe) (1)	353,642	444,082	797,724
Relative percentage	44 %	56 %	100 %
Proved developed %	82 %	83 %	83 %
Net sales volumes			
Crude oil (MBbl)	27,057	30,968	58,025
Natural gas (MMcf)	117,051	101,854	218,905
NGL (MBbl)	13,954	17,672	31,626
Total net sales volumes (MBoe) (1)	60,519	65,616	126,135
Average daily equivalents (MBoe/d) (1)	165.4	179.3	344.7
Relative percentage	48 %	52 %	100 %

(1) Amounts may not calculate due to rounding.

Total proved reserves as of December 31, 2024 increased 14% from December 31, 2023. Average daily equivalent sales volumes as of December 31, 2024 increased 63% from December 31, 2023, primarily as a result of the Hibernia, Tap Rock, and Vencer acquisitions.

DJ Basin. Our DJ Basin assets are comprised of approximately 356,800 net acres located primarily in Weld, Arapahoe, Adams, and Boulder counties, Colorado. Our operations in the DJ Basin primarily target the Niobrara and Codell formations. In 2024, we averaged 1.3 drilling rigs and 1.5 completion crews in the DJ Basin that allowed us to drill 85 gross (75.1 net) operated wells, complete 94 gross (82.8 net) operated wells, and turn to sales 115 gross (103.9 net) operated wells.

Net sales volumes in the DJ Basin for the year ended December 31, 2024, was 60,519 MBoe, a 2% decrease from 61,514 MBoe for the year ended December 31, 2023. Estimated proved reserves in the DJ Basin increased slightly at 353,642 MBoe as of December 31, 2024, compared to 351,897 MBoe as of December 31, 2023.

Permian Basin. Our Permian Basin assets are comprised of approximately 120,400 net acres located primarily in Upton, Reagan, Glasscock, Martin, Midland, Reeves, and Loving 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 2024, we averaged 4.5 drilling rigs and 2.0 completion crews that allowed us to drill 122 gross (114.0 net) operated wells, complete 136 gross (123.3 net) operated wells, and turn to sales 122 gross (107.6 net) operated wells in the Permian Basin.

Net sales volumes in the Permian Basin for the year ended December 31, 2024, was 65,616 MBoe, a 312% increase from 15,916 MBoe for the year ended December 31, 2023. Estimated proved reserves in the Permian Basin increased 28% to 444,082 MBoe as of December 31, 2024, from 345,902 MBoe as of 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 estimated proved reserves do not include probable or possible reserves. For a definition of proved reserves under the SEC rules, refer to the “*Glossary of Crude Oil and Natural Gas Terms*” included at the beginning of this report.

Estimated proved reserves are inherently imprecise, and estimates for undeveloped properties are more imprecise than reserve estimates for producing crude oil and natural gas properties. Accordingly, our estimated proved reserves 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, 2024, 2023, and 2022. 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 estimated proved reserves nor does it reflect current or expected commodity price realizations.

	As of December 31,		
	2024	2023	2022
Reserves volumes:			
Estimated proved reserves:			
Crude oil (MBbl)	305,361	272,805	152,602
Natural gas (MMcf)	1,539,518	1,320,302	867,500
NGL (MBbl)	235,776	204,943	118,834
Total proved reserves (MBoe)[1]	797,724	697,799	416,019
Percent crude oil and liquids	68 %	68 %	65 %
Reserves data (in millions):			
Standardized measure	$ 8,315	$ 8,269	$ 7,927
Estimated undiscounted future net cash flows	12,509	12,937	12,527
PV-10[2]	9,215	9,380	9,834
12-month trailing average prices[3]:			
Crude oil (per Bbl)	$ 75.48	$ 78.22	$ 93.67
Natural gas (per MMBtu)	2.13	2.64	6.36

(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 estimated proved reserves 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, 2024:

Operating Region/Area	Crude Oil (MBbls)	Natural Gas (MMcf)	NGL (MBbls)	Crude Oil Equivalent (MBoe)	Percent
Proved developed reserves:					
DJ Basin	103,812	647,550	79,431	291,168	44 %
Permian Basin	131,814	676,306	123,751	368,283	56 %
Total proved developed reserves	235,626	1,323,856	203,182	659,451	100 %
Proved undeveloped reserves:					
DJ Basin	34,045	99,276	11,883	62,474	45 %
Permian Basin	35,690	116,386	20,711	75,799	55 %
Total proved undeveloped reserves	69,735	215,662	32,594	138,273	100 %
Proved reserves:					
DJ Basin	137,857	746,826	91,314	353,642	44 %
Permian Basin	167,504	792,692	144,462	444,082	56 %
Total proved reserves[1]	305,361	1,539,518	235,776	797,724	100 %

(1) Items may not recalculate due to rounding.

Proved undeveloped locations in our December 31, 2024 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. In 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, 2024, we had 291 gross proved undeveloped locations compared to 305 as of December 31, 2023. Our gross proved undeveloped drilling locations as of December 31, 2024 have an average lateral length of approximately two miles.

Total estimated proved reserves as of December 31, 2024 increased 99.9 MMBoe, or 14%, to 797.7 MMBoe when compared to December 31, 2023. A summary of our changes in quantities of total proved reserves for the year ended December 31, 2024 is as follows:

	Net Reserves (MBoe)
Beginning of year	697,799
Extensions, discoveries, and other additions	101,817
Production	(126,135)
Divestiture of reserves	(22,929)
Removed from capital program	(24,064)
Acquisition of reserves	179,348
Revisions to previous estimates	(8,112)
End of year	797,724

The 179.3 MMBoe of acquisition of reserves is comprised of 163.1 MMBoe acquired in the Vencer Acquisition and 16.2 MMBoe of various acquisitions and acreage exchanges in our operated wells. The 101.8 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 58.4 MMBoe through 140 gross proved undeveloped location additions and 43.4 MMBoe of new proved developed reserves that did not have any associated proved undeveloped reserves recorded as of December 31, 2023. The 8.1 MMBoe negative revision of proved reserves as compared to previous estimates was the result of: (i) negative revisions of 23.0 MMBoe driven by 2024 negative Waha pricing differentials, natural gas shrinks, and NGL yields, (ii) negative revisions of 12.8 MMBoe from non-producing wells that have been or are planned to be plugged and abandoned, and (iii) negative price-related revisions of 9.6 MMBoe that resulted from the decrease to SEC prices of $2.74 to $75.48 per Bbl WTI for crude oil and $0.51 to $2.13 per MMBtu HH for natural gas. Negative revisions were partially offset by 27.6 MMBoe from updates to well performance and 9.7 MMBoe for increases in interest and other.

Proved Undeveloped Reserves

A summary of our changes in quantities of proved undeveloped reserves for the year ended December 31, 2024 is as follows:

	Net Reserves (MBoe)
Beginning of year	156,560
Converted to proved developed	(81,806)
Acquisition of reserves	26,819
Additions from capital program	58,398
Removed from capital program	(24,064)
Revisions to previous estimates	2,366
End of year	138,273

During 2024, we converted 52% of our proved undeveloped reserves, which is comprised of 146 gross wells representing net reserves of 81.8 MMBoe, at a cost of $854.8 million. The 26.8 MMBoe of acquisition of reserves is primarily related to the Vencer Acquisition. During the year, we added 140 gross proved undeveloped locations for a total reserve addition of 58.4 MMBoe. Increases in expected performance offset a decrease in SEC pricing year-over-year resulting in an overall positive revision of 2.4 MMBoe.

Proved Reserves Sensitivity Analysis

If crude oil and natural gas SEC prices declined by 10%, our proved reserve volumes would decrease by 4% and our PV-10 value as of December 31, 2024 would decrease by approximately 19% or $1.8 billion. If crude oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 3% and our PV-10 value as of December 31, 2024 would increase by approximately 20% or $1.8 billion.

Internal Controls Over Estimated Proved Reserves

Our policies regarding internal controls over the recording of proved reserves estimates require proved 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. Our proved reserves are estimated at the property level and compiled for reporting purposes by a group of experienced reservoir engineers. These engineers interact with engineering and geoscience personnel in each of our operating areas, and with accounting, marketing, and other employees, to obtain the necessary data for projecting future production, costs, net revenues, and ultimate recoverable reserves. All relevant data is compiled in a computer database application, to which only authorized personnel are given security access rights consistent with their assigned job function.

In determining our estimated proved reserves, we use a combination of performance methods, including decline curve analysis and other computational methods, offset analogies, and seismic data and interpretation. Inputs and major assumptions related to our estimated proved reserves are reviewed annually by an internal team composed of reservoir engineers, geoscientists, land, and management for adherence to SEC definitions and guidance through a detailed review of land and accounting records, available geological and reservoir data, and production performance data.

Annually, our estimated proved reserves are reviewed by our responsible technical person who oversees the preparation of our proved reserves estimates. 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 estimated proved reserves is our Director, Corporate Reserves, who has over 35 years of experience in the crude oil and natural gas industry, including eight years in the role at Civitas. The Director, Corporate Reserves is a qualified reserve evaluator whose professional qualifications include a bachelor’s degree in Mathematics and Computer Science from the Colorado School of Mines.

Third Party Involvement in Estimated Proved Reserves

We engaged an independent, third-party petroleum engineering consulting firm, Ryder Scott Company, L.P. (“Ryder Scott”) to audit our estimated proved reserves as of December 31, 2024 and prepare our estimated proved reserves as of December 31, 2023 and 2022. Ryder Scott is engaged by and has direct access to the Audit Committee.

As of December 31, 2024, Ryder Scott performed an independent audit of our estimated proved reserves using its own engineering assumptions, but with economic and ownership data we provided. A copy of the audit letter of Ryder Scott is filed as Exhibit 99.1 to this Annual Report on Form 10-K. In the aggregate, the estimated proved reserve amounts of our audited properties determined by Ryder Scott are required, according to our policy, to be within 10 percent of our estimated proved reserve amounts for the total Company, as well as for each respective major asset.

As of December 31, 2023 and 2022, Ryder Scott prepared our proved reserves estimates. In determining our estimated proved reserves, Ryder Scott used a combination of performance methods, including decline curve analysis and other computational methods, offset analogies, and seismic data and interpretation. Economic and ownership data was provided to Ryder Scott for use in their determination of our estimated proved reserves. When preparing our estimated proved reserves, Ryder Scott did 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 prepared our estimated proved reserve in conjunction with an ongoing review by our engineers. A final comparison of data was performed to ensure that the estimated proved reserves are complete, determined pursuant to acceptable industry methods, and with a level of detail we deemed appropriate.

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 overseeing the independent audit of our estimated proved reserves is set forth in the Ryder Scott audit 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 Adjusted 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 Adjusted Free Cash Flow, while maintaining broadly flat production.

The following table presents crude oil, natural gas, and NGL sales volumes by operating region for the periods presented. For additional information, refer to the information set forth in "*Part II - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*"

	Year Ended December 31,		
	2024	2023	2022
Crude oil (MBbls)			
DJ Basin	27,057	28,925	27,651
Permian Basin	30,968	7,801	—
Total	58,025	36,726	27,651
Natural gas (MMcf)			
DJ Basin	117,051	110,339	112,478
Permian Basin	101,854	23,482	—
Total	218,905	133,821	112,478
NGL (MBbls)			
DJ Basin	13,954	14,199	15,666
Permian Basin	17,672	4,201	—
Total	31,626	18,400	15,666
Total sales volumes (MBoe)			
DJ Basin	60,519	61,514	62,063
Permian Basin	65,616	15,916	—
Total	126,135	77,430	62,063

The following table sets forth information regarding crude oil, natural gas, and NGL sales prices, excluding the impact of commodity derivatives and production costs for the periods presented. For additional information, refer to the information set forth in "*Part II - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*"

	Year Ended December 31,		
	2024	2023	2022
Crude oil (Per Bbl)			
DJ Basin	$ 74.07	$ 74.01	$ 91.70
Permian Basin	$ 76.30	$ 81.37	$ —
Total	$ 75.26	$ 75.57	$ 91.70
Natural gas (Per Mcf)			
DJ Basin	$ 1.92	$ 2.54	$ 6.15
Permian Basin	$ (0.56)	$ 1.07	$ —
Total	$ 0.77	$ 2.28	$ 6.15
NGL (Per Bbl)			
DJ Basin	$ 24.44	$ 23.01	$ 35.76
Permian Basin	$ 18.44	$ 15.75	$ —
Total	$ 21.09	$ 21.35	$ 35.76
Production cost (Per Boe)[1]			
DJ Basin	$ 4.09	$ 3.93	$ 3.25
Permian Basin	$ 5.77	$ 6.59	$ —
Total	$ 4.96	$ 4.47	$ 3.25

(1) 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, 2024, we had working interests in a total of 5,136 gross productive wells, of which 3,929 were horizontal. Our working and net revenue interest in our productive wells averaged approximately 79% and 64%, respectively. As of December 31, 2024, we operated a total of 4,802 gross productive wells, of which 3,679 were horizontal. Our working and net revenue interest in our operated productive wells averaged approximately 83% and 68%, 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, 2024:

	Crude Oil		Natural Gas		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
DJ Basin	3,443	2,706	139	123	3,582	2,829	3,485	2,813
Permian Basin	1,459	1,172	95	53	1,554	1,225	1,317	1,195
Total	4,902	3,878	234	176	5,136	4,054	4,802	4,008

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,					
	2024		2023		2022	
	Gross	Net	Gross	Net	Gross	Net
Development wells turned to sales						
DJ Basin	115	103.9	148	124.3	146	129.5
Permian Basin(1)	122	107.6	78	66.0	—	—
Total	237	211.5	226	190.3	146	129.5
Developmental wells - dry holes						
Permian Basin(1)(2)	—	—	2	1.7	—	—

(1) Drilling and completion activity in the Permian Basin for 2023 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, 2024, 2023, and 2022. Additionally, we did not have any dry wells in the DJ Basin during the same periods.

	As of December 31, 2024	
	Gross	Net
In-process development wells		
DJ Basin	36	29.6
Permian Basin	76	72.1
Total	112	101.7

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, 2024. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this summary; however, it does include leasehold acres that we own an underlying mineral interest in.

	Developed Acres(1)		Undeveloped Acres(2)		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
DJ Basin	324,300	287,600	103,900	69,200	428,200	356,800
Permian Basin	129,800	88,800	36,200	31,600	166,000	120,400
Other(3)	104,700	43,400	14,000	9,600	118,700	53,000
Total	558,800	419,800	154,100	110,400	712,900	530,200

(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 14,300 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, 2024, 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 2025		Expiring 2026		Expiring 2027		Expiring 2028 and Beyond	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
DJ Basin	9,000	5,700	6,400	3,600	1,600	1,000	2,500	2,500
Permian Basin	2,600	2,100	4,400	1,000	500	100	1,200	800
Other	—	—	800	800	—	—	—	—
Total	11,600	7,800	11,600	5,400	2,100	1,100	3,700	3,300

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, and basis protection swaps. The crude oil instruments are indexed to NYMEX WTI prices, and natural gas instruments are indexed to NYMEX HH and Waha prices, all of which have a high degree of historical correlation with actual prices received, before differentials. 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 Data - Note 9 - Derivatives*" for additional discussion.

Purchasers

In 2024, we had three purchasers that represented a combined total of 35% of our revenue; Purchaser A accounted for 15% of revenue, Purchaser B accounted for 10% of revenue, and Purchaser C accounted for 10% 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. Refer to "*Part II - Item 8. Financial Statements and Supplementary Data - 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. Refer to *"Risks Related to Our Business and Operations - The oil and natural gas industry is highly competitive and many of our competitors have available resources in excess of our own."* 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 driven by extreme high temperatures 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. 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, 2024, we had 655 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 talented employees possess a vast array of skills including engineering, geoscience, midstream operations, production, safety, land, 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

At Civitas, safety is a foundational value. The health and safety of our employees, contractors, suppliers, and the communities in which we operate is paramount. We are committed to maintaining a safe and healthy work environment through rigorous safety protocols, continuous training, and strict adherence to regulatory standards. This commitment has led to a Total Recordable Incident Rate ("TRIR") of 0.25 in 2024, which is below the industry average determined by the U.S. Bureau of Labor Statistics. This outstanding performance underscores our dedication to safety and our proactive approach to risk management.

Our operations seek to comply with all relevant federal and state health and safety regulations, including the federal Occupational Safety and Health Act ("OSHA") and comparable state laws. We adhere to the OSHA hazard communication standard and the U.S. Environmental Protection Agency (the "EPA") community right-to-know regulations under Title III of the Superfund Amendments and Reauthorization Act. These regulations outline that information about hazardous materials used or produced in our operations is readily available to employees, government authorities, and the public.

We foster a culture of safety by integrating environmental, health, and safety metrics, such as TRIR and spill count, into our internal performance metrics and compensation structure. Our commitment to safety is a cornerstone of our operational excellence and long-term success.

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, parental leave, 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, 2024.

Approximately 27% of our total workforce are women, and 20% are members of a minority group, as of December 31, 2024. As of the same date, 27% of our executives (as defined as persons at the level of Vice President and higher) are women, and 23% are members of a minority group.

Offices

As of December 31, 2024, 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 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 the Federal Energy Regulatory Commission (“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 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 sought to 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 sought to remove 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 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, until March 2026 to develop and submit their plans for reducing methane from existing sources. The final emissions guidelines under Subpart OOOOc provides until 2029 for existing sources to comply. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Consequently, future implementation and enforcement of the final rule remains uncertain at this time.

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 NAAQS since their adoption, and its existing nonattainment 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 nonattainment 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 redesignation. In response, the EPA chose to redesignate the boundary for the 2015 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. In addition, in July 2022, the EPA announced that it was considering redesignating an area comprising several Texas and New Mexico counties in the Permian Basin as a new ozone nonattainment area, but the EPA deprioritized the redesignation in 2023. In January 2025, the Biden administration finalized a rule implementing deadlines and setting requirements for areas reclassified as nonattainment areas for ozone, including areas in Colorado. However, the effective date of this rule is under review pursuant to an executive order signed by President Trump in January 2025. If in the future, the areas in which we operate are redesignated as nonattainment areas, this could subject us to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. In addition, the EPA reviewed the 2015 70 ppb standard in 2020, but retained the standard without revision ("2020 NAAQS"). However, the EPA announced in August 2023 that it is re-reviewing the science underlying the 2020 NAAQS for ozone to determine whether to retain the current ozone national ambient air quality standards or implement more stringent standards. Future actions to lower the standard could similarly result in additional fees or more stringent permitting.

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 intensity targets within the rule are phased in and begin decreasing over five years, starting 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.

In 2021 the New Mexico Energy, Minerals and Natural Resources Department enacted a rule, which requires oil and gas operators to capture 98% of their produced natural gas by December 31, 2026, and prohibits routine venting and flaring.

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; however, the EPA has taken no further action in response to the study to date. In April 2024, the Bureau of Land Management ("BLM") finalized a rule to reduce the waste of natural gas from venting, flaring and leaks during oil and gas production activities on federal and Indian leases, which became effective in June 2024. However, North Dakota, Texas, Montana, Wyoming and Utah challenged the rule, and litigation is ongoing in the District of North Dakota, which granted a preliminary injunction enjoining BLM from enforcing the rule in the plaintiff states in September 2024. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. As a result, future implementation and enforcement of this rule remains uncertain at this time.

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. These and any other new rules could substantially increase 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 November 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. The New Mexico Environment Department is expected to finalize the rule in 2025.

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 effective 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 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, the Inflation Reduction Act of 2022 (the “Inflation Reduction Act”) was signed into law. Among other things, the Inflation Reduction Act 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. To implement the program, in May 2024, the EPA finalized revisions to the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. Among other things, the new 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 emissions reported under the Greenhouse Gas Reporting Program will be the basis for any payments under the Methane Emissions Reduction Program. However, petitions for reconsideration to EPA are pending and litigation in the D.C. Circuit has commenced. In November 2024, EPA finalized a rule to implement the Inflation Reduction Act’s Waste Emissions Charge. The fee imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 is $900 per ton emitted over annual methane emissions thresholds, and increases to $1,200 in 2025, and $1,500 in 2026. In January 2025, industry associations challenged the Waste Emissions Charge rule in the D.C. Circuit. The emissions fee and funding provisions of the Inflation Reduction Act could increase operating costs within the oil and gas industry and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Consequently, future implementation and enforcement of these rules remains uncertain at this time.

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 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. At the 27th Conference of the Parties, the U.S. 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. At the 28th Conference of the Parties, 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. However, in January 2025, President Trump issued an executive order directing the immediate notice to the United Nations of the United States’ withdrawal from the Paris Agreement and all other agreements made under the United Nations Framework Convention on Climate Change. The full impact of these actions remains unclear at this time. At the same time, various state and local governments have publicly committed to furthering the goals of the Paris Agreement, and many related initiatives are expected to continue.

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 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. However, in January 2025, President Trump issued executive orders directing an immediate pause on the disbursement of funds appropriated through the Inflation Reduction Act.

In May 2019, Colorado passed GHG inventory legislation and climate action legislation. House Bill 19-1261 concerns the reduction of GHG pollution and established statewide GHG pollution reduction goals. Senate Bill 19-096 concerns the collection of GHG 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, in January 2021, the Colorado Energy Office and Colorado Department of Public Health and Environment finalized a Greenhouse Gas Pollution Reduction Roadmap. 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 (“GEMM 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 following a review of GEMM 2 by the end of 2025.

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 align the January 2023 rule 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. However, roughly half of the states and other plaintiffs are continuing to challenge the rule, and EPA and the Corps are using the pre-2015 definition of WOTUS in these states while litigation continues. As a result, substantial uncertainty exists with respect to future implementation of the September 2023 rule and the scope of CWA jurisdiction more generally. Any expansion to CWA jurisdiction could impact areas where oil and gas operations are conducted. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. In 2021, the United States Supreme Court held that the CWA requires a discharge permit if the addition of pollutants through groundwater is the functional equivalent of a direct discharge from the point source into navigable waters. In November 2023, the EPA issued draft guidance describing the information that should be used to determine which discharges through groundwater may require a permit. However, in January 2025, President Trump issued executive orders directing (i) the EPA and the Corps to identify planned or potential actions that could be subject to emergency treatment under Section 404 of the CWA and (ii) the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions, including all existing regulations and guidance documents, that are unduly burdensome on the identification, development, or use of domestic energy resources. Accordingly, future implementation and enforcement of these rules and policies is uncertain at this time.

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. However, in January 2025, President Trump issued an executive order instructing the Corps to use emergency authorities and NWPs to grant approvals for energy projects under Section 404 of the CWA. As a result, any future revisions to NWPs, including NWP 12, are uncertain at this time. 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") was established to protect endangered and threatened species and their habitats. If a species is listed as threatened or endangered pursuant to the ESA, restrictions may be imposed on activities adversely affecting that species or its habitat. The U.S. Fish and Wildlife Service ("FWS") must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. 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. However, the Department of the Interior has not yet issued proposed rulemaking regulations. As a result, future amendments to the MBTA are uncertain. In April 2024, the FWS issued three final rules governing critical habitat designation and expanding protection options for species listed as threatened pursuant to the ESA. 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 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 May 2024, CEQ finalized the Phase II rulemaking, which generally 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. However, at least twenty states challenged the Phase II rule in federal district court. In addition, in January 2025, President Trump issued executive orders directing (i) CEQ to provide guidance on implementing NEPA and to propose rescinding and replacing CEQ's NEPA regulations with implementing regulations at the agency level and (ii) federal agencies to adhere to only the relevant legislated requirements for environmental reviews and to prioritize efficiency and certainty over any other objectives in such reviews. In February 2025, CEQ sent an interim final rule to the White House Office of Management and Budget that would immediately withdraw the NEPA implementing regulations. The potential impact of further changes to the NEPA regulations and statutory text therefore remains uncertain and could have an effect on our business and operations.

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, Sustainability 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.

Risks Related to Commodity Prices

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.

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, 2024, the daily NYMEX WTI crude oil spot price ranged from a high of $86.91 per Bbl to a low of $65.75 per Bbl, and the NYMEX HH natural gas spot price ranged from a high of $13.20 per MMBtu to a low of $1.21 per MMBtu. As of February 21, 2025, the daily NYMEX WTI crude oil spot price and NYMEX HH natural gas spot price was $70.40 per Bbl and $4.23 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 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 and policies, including regulations addressing climate change and trade policies, including tariffs;
- 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.

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.

Risks Related to Our Reserves, Leases, and Drilling Locations

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 crude oil and natural gas reserves and the PV-10 (a non-GAAP financial measure) as of December 31, 2024, 2023, and 2022.

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 audited or 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, 2024, 2023, and 2022, 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.

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.

The development of our proved undeveloped 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, 2024, approximately 17,600 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 7,800 net acres will expire in 2025, approximately 5,400 net acres will expire in 2026, and approximately 4,400 net acres will expire in 2027 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.

Risks Related to Our Business and 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 *"Risks Related to Our Reserves, Leases, and Drilling Locations - 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*" above. 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;
- access to and availability of reliable sources of electric power;
- title issues or inaccuracies;
- safety and/or environmental conditions; and
- limitations in the market for crude oil and natural gas.

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.

We intend to pursue the further development of our properties through horizontal drilling and completion, which can be operationally challenging and costly.

Horizontal drilling can be complex and expensive. 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.

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.

Our ability to sell crude oil, natural gas, and NGLs, and receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines, and other transportation systems owned or operated by third-parties or by other interruptions beyond our control, which could impact the marketability of our production.

The marketability of our crude oil, natural gas, and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities, pipelines, and other transportation systems, which are generally owned or operated by third parties. Any significant interruption in service from, damage to, or lack of available capacity in these systems and facilities can result in the shutting-in of our producing wells, delay or discontinuance of development plans for our properties, increases in costs attributed to obtaining alternative takeaway capacity on less favorable terms, or lower price realizations. Additionally, federal and state regulation concerning the production and transportation of crude oil, natural gas, and NGLs, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines or processing facilities, infrastructure or capacity constraints, and our voluntary curtailment of production in response to market or other conditions could adversely affect our ability to produce, gather, process, transport, or market crude oil, natural gas, and NGLs. If a substantial amount of our production is interrupted at the same time, our business, results of operations, and financial condition may be materially adversely affected.

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.

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.

The oil and natural gas industry is highly competitive and many of our competitors have available resources in excess of our own.

The oil and natural gas industry is highly competitive. Many of our competitors, including major integrated and independent oil and natural gas companies, are larger and have substantially greater resources at their disposal than we do and may have a competitive advantage over us. For example, many oil and gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for exploratory and development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for properties. As a result, we may not be successful in acquiring and developing profitable properties.

In addition, other companies may have a greater ability to continue drilling activities during periods of low oil or gas prices and to absorb the burden of current and future governmental regulations and taxation, shortages of equipment, labor, or materials. As a result of this intense competition, we may incur increased costs or be unable to obtain the resources needed for our operations. If we are unable to effectively compete with our competitors, our business, results of operations, and financial condition may be materially adversely affected.

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 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.

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 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 Derivative Activities, Debt Agreements, and Access to Capital

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, which may 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.

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 $125.0 million as of December 31, 2024, and the sale of our crude oil, natural gas, and NGL totaling $646.3 million in receivables as of December 31, 2024, 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.

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 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 were 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.

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, 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.

Risks Related to Legislative and Regulatory Initiatives

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.

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 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.

Climate change laws and regulations restricting emissions of GHGs 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 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 sought to 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 removed an emissions monitoring exemption for small wellhead-only sites and created 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 until March 2026. The final emissions guidelines under Subpart OOOOc provide until 2029 for existing sources to comply. The final rule is subject to ongoing litigation but remains in effect. 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. However, in January 2025, President Trump issued an executive order directing the heads of all federal agencies to identify and begin the processes to suspend, revise, or rescind all agency actions that are unduly burdensome on the identification, development, or use of domestic energy resources. Consequently, future implementation and enforcement of the final rule remains uncertain at this time.

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.

The adoption and implementation of new or more stringent federal, state, or local legislation or regulatory programs to reduce emissions of GHGs (including carbon pricing schemes), or 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. While the Supreme Court's decision in *Loper Bright Enterprises v. Raimondo* to overrule *Chevron U.S.A. Inc. v.*

Natural Resources Defense Council, Inc. and end the concept of general deference to regulatory agency interpretations of laws introduces new complexity for federal agencies and administration of climate change policy and regulatory programs, many of these initiatives are expected to continue. 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. In addition, any 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 climate change.

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 and availability of 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. 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 sustainability strategy, including any specific sustainability 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 sustainability 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 sustainability matters. Further, failure or a perception (whether or not valid) of failure to implement our sustainability 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 sustainability strategy, including any sustainability 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.

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 requires certain parties to derivative contracts to comply with margin requirements, though we likely qualify for a commercial end-user exemption from such requirements. 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 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 may occur unexpectedly. 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, 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. While we do not currently expect the Inflation Reduction Act to have a material impact on our effective tax rate, it is possible that the Inflation Reduction Act (or implementing regulations and other guidance) 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 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.

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 2024 calendar year, the closing sales price of our common stock ranged from a low of $42.79 per share to a high of $78.16 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 (the "NYSE"), 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, or repurchase shares of common stock from, 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.

The decision to pay any future dividends or conduct future stock repurchases is solely within the discretion of, and subject to approval by, our Board. Our Board's determination with respect to any such stock repurchases or dividends, including with respect to dividends, 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 or conduct stock repurchases in the future in the current amounts or at all. Our Board may change the timing and amount of any future stock repurchases or dividend payments or eliminate such stock repurchases or 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 and conduct stock repurchases from 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 and stock repurchases under the Delaware General Corporation Law (the "DGCL"). Under the DGCL, our Board may not authorize a dividend or repurchase of our common stock unless such dividend or repurchase is either paid for out of our surplus, as calculated in accordance with the DGCL, or if we do not have a surplus, such dividend or repurchase is paid for out of our net profits for the fiscal year in which such dividend is declared or stock repurchase conducted and/or the preceding fiscal year. In addition, our ability to pay cash dividends to and conduct stock repurchases from 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 or repurchase of our common stock. Any elimination of, or revision in, our stock repurchase program or dividend policy 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.

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 ("VP-IT") 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. The VP-IT 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. The VP-IT has over 25 years of information technology management experience and has served as our VP-IT since January 2024.

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 third-party cybersecurity solutions to actively manage threats to our information technology environment 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, refer to "*Item 1A. Risk Factors - Risks Related to Our Business and Operations - 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*."

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 reasonably believe could exceed a specified threshold. Pursuant to Item 103 of Regulation S-K, we have elected to apply a threshold of the lesser of $1.0 million or 1% of total current assets for purposes of determining whether disclosure of any such proceedings is required. Applying this threshold, we are not aware of any such proceedings required to be disclosed for the year ended December 31, 2024.

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 21, 2025, there were approximately 111 registered holders of our common stock.

Dividend Policy. As approved by our Board, cash dividends are comprised of a quarterly base dividend and a discretionary variable component.

The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our 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. For additional information on restrictions on our ability to pay cash dividends on our common stock, refer to "*Item 1A. Risk Factors – Risks Related to Our Common Stock - Our ability to pay dividends to or repurchase shares of common stock from 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*" and "*Item 8. Financial Statements and Supplementary Data - Note 5 - Debt.*"

Issuer Purchases of Equity Securities. The following table provides information about our purchases of our common stock during the three months ended December 31, 2024.

	Total Number of Shares Purchased[1]	Average Price Paid per Share[2]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[3]	Maximum Dollar Value that May Yet be Purchased as Part of Publicly Announced Plans or Programs (in thousands)[3]
October 1, 2024 – October 31, 2024	578,459	$ 51.91	577,936	$ 392,038
November 1, 2024 – November 30, 2024	1,118,842	51.65	1,115,264	334,437
December 1, 2024 – December 31, 2024	1,482,941	47.16	1,479,563	264,659
Total	3,180,242	$ 49.60	3,172,763	$ 264,659

(1) Purchases outside of the 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.

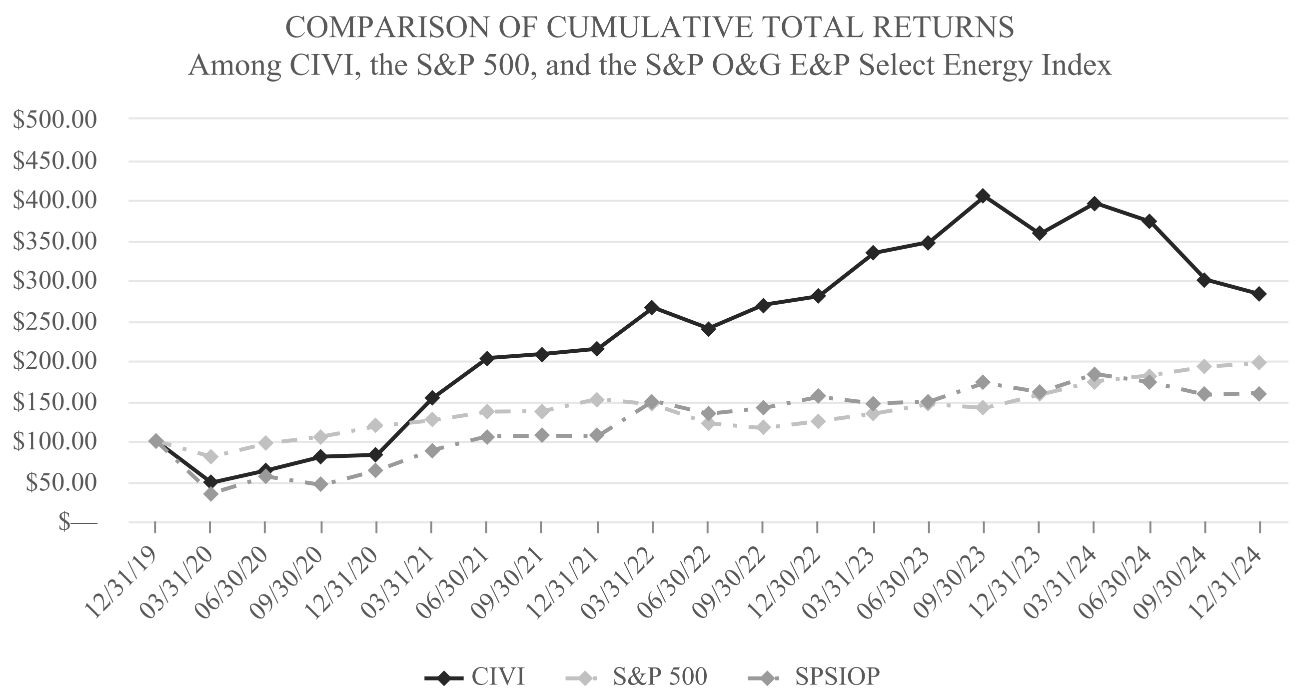
(2) Excludes commissions paid and excise taxes accrued related to stock repurchases.

(3) On July 30, 2024, our Board authorized a new stock repurchase program authorizing repurchases of up to $500 million of our outstanding shares of common stock, replacing our prior stock repurchase program, pursuant to which we are authorized, from time to time, to 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 Rule 10b-18 and Rule 10b5-1 of the Exchange Act. The stock repurchase program does not have a termination date, does not require any specific number of shares to be acquired, and can be modified or discontinued by our Board at any time.

Sale of Unregistered Securities. Other than as previously reported on our Current Reports on Form 8-K, filed with the SEC on October 4, 2023 and January 2, 2024, we had no sales of unregistered securities during the year ended December 31, 2024.

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, 2019 through December 31, 2024. The graph assumes that $100 was invested on December 31, 2019 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 2024 and 2023 results and year-to-year comparisons between 2024 and 2023. Discussions of 2022 items and year-to-year comparisons between 2023 and 2022 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, 2023.

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 from our premier assets in the DJ Basin in Colorado and the Permian Basin in Texas and New Mexico. Our proven business model to maximize stockholder returns is focused on four key strategic pillars: generate significant free cash flow, maintain a premier balance sheet, return capital to our stockholders, and demonstrate ESG leadership.

Financial and Operating Results

Our financial and operational results for the year ended December 31, 2024:

- Total sales volumes increased 63% when compared to the year ended December 31, 2023; average sales volumes per day increased to 345 MBoe/d compared to 212 MBoe/d during the year ended December 31, 2023, in each case, primarily as a result of the Hibernia, Tap Rock and Vencer Acquisitions;

- Net income of $838.7 million, or $8.46 per diluted share for the year ended December 31, 2024 compared to $784.3 million, or $9.02 per diluted share for the year ended December 31, 2023;

- Cash flows provided by operating activities were $2.9 billion compared to $2.2 billion during the year ended December 31, 2023. Adjusted Free Cash Flow[1] was $1.3 billion compared to $795.9 million during the year ended December 31, 2023;

- Capital expenditures in drilling, completions, facilities, land, midstream assets, and other were $1.9 billion;

- Cash dividends paid of $493.8 million;

- Repurchased approximately 7.3 million shares of our common stock totaling $427.2 million at a weighted average price of $58.42 per share; and

- Proved reserves increased by 14% to 797.7 MMBoe when compared to December 31, 2023, primarily as a result of the Vencer Acquisition.

(1) Adjusted Free Cash Flow is a non-GAAP financial measure. Refer to "Non-GAAP Financial Measures - *Reconciliation of Adjusted Free Cash Flow to Cash Provided by Operating Activities*" and "*Liquidity and Capital Resources*" below for additional discussion.

2024 Transaction and Operations

On January 2, 2024, we completed the acquisition of certain crude oil and natural gas assets from Vencer. The Vencer Acquisition included approximately 44,000 net acres in the Midland Basin, which is part of the larger Permian Basin, and certain related crude oil and natural gas assets with average production of approximately 49 MBoe per day as of January 2, 2024 in exchange for aggregate adjusted consideration of approximately $2.0 billion, consisting of $1.0 billion in cash paid at the closing of the Vencer Acquisition, 7.2 million shares of our common stock issued at the closing of the Vencer Acquisition, and $550.0 million in cash to be paid on or before January 3, 2025, inclusive of customary post-closing adjustments. In 2024, we made two early payments totaling $75.0 million towards the deferred consideration. The remaining balance of $475.0 million was paid on January 3, 2025. The initial cash portion of the acquisition was funded by cash on hand and the issuance of $1.0 billion in aggregate principal amount of our 2030 Senior Notes. Refer to "*Item 8. Financial Statements and Supplementary Data - Note 2 - Acquisitions and Divestitures*" and "*Item 8. Financial Statements and Supplementary Data - Note 5 - Debt*" for additional discussion.

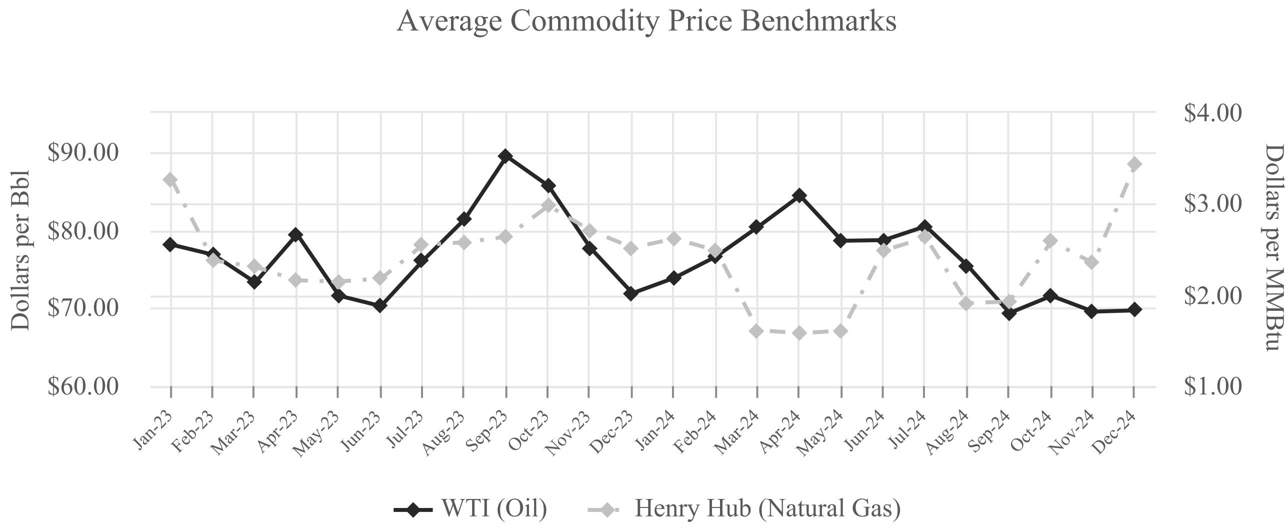
During 2024, our total capital expenditures in drilling, completions, land, and midstream assets were $1.9 billion. In the DJ Basin, we operated approximately 1.3 drilling rigs and 1.5 completion crews, allowing us to drill 85 gross (75.1 net) operated wells and turn to sales 115 gross (103.9 net) operated wells. In the Permian Basin, we operated approximately 4.5 drilling rigs and 2.0 completion crews, allowing us to drill 122 gross (114.0 net) operated wells and turn to sales 122 gross (107.6 net) operated wells.

Commodity Prices and Certain Other Market Conditions

The crude oil and natural gas industry is cyclical and commodity prices are inherently volatile. Commodity prices in 2024 continued to be impacted by various macro-economic factors influencing the balance of supply and demand. From January through April 2024, pricing for crude oil rebounded when compared to declining pricing in the fourth quarter of 2023. The rebound was a result of concerns over lower oil supply driven by uncertainties around political conditions in or affecting other crude oil producing countries, including the Israel-Palestine conflict. Additionally, in the first half of 2024, OPEC+ continued production cuts to seek to stabilize the crude oil market. Despite OPEC+'s efforts to constrain production, non-OPEC+ countries continue to have an impact on pricing by increasing overall output in the second half of 2024, including the U.S., which production reached a monthly record in October 2024. Further, weakening global economic growth has been contributing downward pressure on the price of oil, with OPEC+ consistently reducing consumption estimates throughout 2024 as a result of China's economic slowdown, specifically in the transportation sector. These factors have led to declining monthly average crude oil prices in the second half of 2024 to the lowest levels seen since 2021.

U.S. inflation rates during 2024 remained relatively stable when compared to 2023, yet slightly 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 monthly average NYMEX WTI crude oil and NYMEX HH natural gas price over the years ended December 31, 2024 and 2023.



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(1) The average NYMEX WTI crude oil price for the years ended December 31, 2024 and 2023 was $75.72 and $77.62, respectively.

(2) The average NYMEX natural gas HH price for the years ended December 31, 2024 and 2023 was $2.27 and $2.74, 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 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 includes a transportation differential for delivery to Cushing, Oklahoma. Our Permian Basin crude oil price includes a transportation differential for delivery to Cushing, Oklahoma. During the year ended December 31, 2024, this differential was a premium to WTI. However, basis differentials can be volatile and can change at various times given their high correlation with market dynamics, supply and demand, and overall production.

Our natural gas production is typically sold at a discount to the benchmark NYMEX HH price. Our DJ Basin natural gas production is sold based on prices established for 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. During the year ended December 31, 2024, the Waha Hub experienced periods of negative pricing due to oversupply, seasonal maintenance, and limited pipeline capacity. Toward the end of 2024, Waha Hub prices momentarily rebounded following Energy Transfer's Warrior Pipeline Final Investment Decision announcement, and December settled at $1.95/MMBtu.

We periodically enter into natural gas basis protection swaps to mitigate a portion of our exposure to adverse market changes. As a result of our natural gas derivative contracts, we recorded a cash settlement gain of $48.1 million during the year ended December 31, 2024. Refer to *Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives* for further discussion on our derivative contracts.

Outlook

Our 2025 capital investments in drilling, completions, and midstream, which we expect to be between $1.8 billion to $1.9 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 2025 capital program allocates slightly more to the Permian Basin as compared to the DJ Basin and level-loads investment to support sustainable capital efficiencies and reduced quarterly volatility, with spend estimated to be 55% in the first half of 2025 compared to 63% in the first half of 2024. The 2025 capital investment plan is anticipated to deliver between 325 to 335 MBoe per day on average for the year. 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, 2024	Year Ended December 31, 2023	Change	Percent Change
Revenues (in thousands):				
Crude oil sales	$ 4,367,108	$ 2,775,364	$ 1,591,744	57 %
Natural gas sales	168,388	305,629	(137,241)	(45)%
NGL sales	666,912	392,828	274,084	70 %
Product revenue	$ 5,202,408	$ 3,473,821	$ 1,728,587	50 %
Sales Volumes:				
Crude oil (MBbls)	58,025	36,726	21,299	58 %
Natural gas (MMcf)	218,905	133,821	85,084	64 %
NGL (MBbls)	31,626	18,400	13,226	72 %
Total sales volumes (MBoe)	126,135	77,430	48,705	63 %
Average Sales Prices (before derivatives):				
Crude oil (per Bbl)	$ 75.26	$ 75.57	$ (0.31)	— %
Natural gas (per Mcf)	0.77	2.28	(1.51)	(66)%
NGL (per Bbl)	21.09	21.35	(0.26)	(1)%
Total (per Boe)	41.24	44.86	(3.62)	(8)%
Average Sales Prices (after derivatives)[(1)]:				
Crude oil (per Bbl)	$ 74.54	$ 73.95	$ 0.59	1 %
Natural gas (per Mcf)	0.99	2.22	(1.23)	(55)%
NGL (per Bbl)	21.09	21.35	(0.26)	(1)%
Total (per Boe)	41.30	43.98	(2.68)	(6)%

(1) 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 *Non-GAAP Financial Measures* below.

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	
	2024	2023	2022	2024-2023	2023-2022
Crude oil (MBbls)					
DJ Basin	27,057	28,925	27,651	(6)%	5 %
Permian Basin	30,968	7,801	—	297 %	100 %
Total	58,025	36,726	27,651	58 %	33 %
Natural gas (MMcf)					
DJ Basin	117,051	110,339	112,478	6 %	(2)%
Permian Basin	101,854	23,482	—	334 %	100 %
Total	218,905	133,821	112,478	64 %	19 %
NGL (MBbls)					
DJ Basin	13,954	14,199	15,666	(2)%	(9)%
Permian Basin	17,672	4,201	—	321 %	100 %
Total	31,626	18,400	15,666	72 %	17 %
Total sales volumes (MBoe)					
DJ Basin	60,519	61,514	62,063	(2)%	(1)%
Permian Basin	65,616	15,916	—	312 %	100 %
Total	126,135	77,430	62,063	63 %	25 %
Average sales volumes per day (MBoe/d)					
DJ Basin	165.4	168.5	170.0	(2)%	(1)%
Permian Basin	179.3	43.6	—	311 %	100 %
Total	344.7	212.1	170.0	63 %	25 %

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

	Year Ended December 31,			Percent Change	
Average Sales Price	2024	2023	2022	2024-2023	2023-2022
Crude Oil (Per Bbl)					
DJ Basin	$ 74.07	$ 74.01	$ 91.70	— %	(19)%
Permian Basin	$ 76.30	$ 81.37	$ —	(6)%	100 %
Total	$ 75.26	$ 75.57	$ 91.70	— %	(18)%
Natural gas (Per Mcf)					
DJ Basin	$ 1.92	$ 2.54	$ 6.15	(24)%	(59)%
Permian Basin	$ (0.56)	$ 1.07	$ —	(152)%	100 %
Total	$ 0.77	$ 2.28	$ 6.15	(66)%	(63)%
NGL (Per Bbl)					
DJ Basin	$ 24.44	$ 23.01	$ 35.76	6 %	(36)%
Permian Basin	$ 18.44	$ 15.75	$ —	17 %	100 %
Total	$ 21.09	$ 21.35	$ 35.76	(1)%	(40)%
Production Cost (Per Boe)[1]					
DJ Basin	$ 4.09	$ 3.93	$ 3.25	4 %	21 %
Permian Basin	$ 5.77	$ 6.59	$ —	(12)%	100 %
Total	$ 4.96	$ 4.47	$ 3.25	11 %	38 %

(1) Represents lease operating expense and midstream operating expense per Boe using total sales volumes and excludes ad valorem and severance taxes.

Crude oil, natural gas, and NGL sales. Total product revenues increased by 50% to $5.2 billion for the year ended December 31, 2024 compared to $3.5 billion for the year ended December 31, 2023. The increase was primarily due to a 63% increase in total sales volumes driven by the Hibernia, Tap Rock, and Vencer acquisitions, partially offset by an 8% decrease in total commodity pricing, excluding the impact of derivatives, with natural gas as the predominate driver.

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

	Year Ended December 31,			
	2024	2023	Change	Percent Change
Operating Expenses:				
Lease operating expense	$ 577,837	$ 301,288	$ 276,549	92 %
Midstream operating expense	48,038	45,080	2,958	7 %
Gathering, transportation, and processing	377,678	290,645	87,033	30 %
Severance and ad valorem taxes	377,388	276,535	100,853	36 %
Exploration	14,322	2,178	12,144	**
Depreciation, depletion, and amortization	2,056,427	1,171,192	885,235	76 %
Transaction costs	31,419	84,328	(52,909)	(63)%
General and administrative expense	226,965	161,077	65,888	41 %
Other operating expense	17,330	7,437	9,893	133 %
Total operating expenses	$ 3,727,404	$ 2,339,760	$ 1,387,644	59 %
Selected Operating Expenses (per Boe):				
Lease operating expense	$ 4.58	$ 3.89	$ 0.69	18 %
Midstream operating expense[1]	0.38	0.58	(0.20)	(34)%
Gathering, transportation, and processing	2.99	3.75	(0.76)	(20)%
Severance and ad valorem taxes	2.99	3.57	(0.58)	(16)%
Depreciation, depletion, and amortization	16.30	15.13	1.17	8 %
Transaction costs	0.25	1.09	(0.84)	(77)%
General and administrative expense	1.80	2.08	(0.28)	(13)%
Total selected operating expenses (per Boe)	$ 29.29	$ 30.09	$ (0.80)	(3)%

** Percent not meaningful

(1) Our midstream assets predominantly relate to our DJ Basin operations. If we were to exclude the production of our Permian Basin assets from this calculation, it would result in a $0.06 per Boe, or 8% increase between the year ended December 31, 2024 and 2023.

Lease operating expense. Lease operating expense increased 92%, to $577.8 million for the year ended December 31, 2024, from $301.3 million for the year ended December 31, 2023, and increased 18% on an equivalent basis per Boe. The increase in lease operating expense was primarily the result of the Tap Rock, Hibernia, and Vencer acquisitions in the Permian Basin. Additionally, our assets in the Permian Basin incurred additional costs for planned maintenance, workover projects, and workover optimizations in the last half of 2024. These increases were slightly offset by the Vencer Acquisition and 2024 development activities in areas of the Permian Basin with lower operating costs. The increase in lease operating expense per Boe was a result of the increased cost of operatorship in the Permian Basin relative to the DJ Basin.

Gathering, transportation, and processing. Gathering, transportation, and processing ("GTP") expense increased 30%, to $377.7 million for the year ended December 31, 2024, from $290.6 million for the year ended December 31, 2023, and decreased 20% on an equivalent basis per Boe. The increase was primarily driven by (i) an increase in natural gas and NGL volumes processed from the Hibernia, Tap Rock, and Vencer acquisitions for a select number of midstream contracts where costs are incurred prior to the transfer of control for approximately $55.0 million, (ii) an increase in production in the DJ Basin under contract terms that are incurred prior to the transfer of control for approximately $30.0 million, and (ii) a slight increase in all GTP contracts as a result of annual price escalations. GTP expense per Boe decreased period over period as, with respect to a significant portion of the midstream contracts assumed in the Hibernia, Tap Rock, and Vencer acquisitions, GTP costs are incurred subsequent to the transfer of control; thereby, these costs are recorded net within crude oil, natural gas, and NGL sales.

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.

Severance and ad valorem taxes increased 36%, to $377.4 million for the year ended December 31, 2024, from $276.5 million for the year ended December 31, 2023, and decreased 16% on an equivalent basis per Boe. Crude oil, natural gas, and NGL sales increased by 50% for the year ended December 31, 2024 when compared to the year ended December 31, 2023, resulting in higher severance and ad valorem taxes on an absolute basis. The decrease in severance and ad valorem taxes per Boe was primarily due to an increase in crude oil, natural gas, and NGL sales generated through the Hibernia and Vencer acquisitions in the state of Texas, which generally levies lower severance and ad valorem tax rates relative to the states of Colorado and New Mexico.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization (“DD&A”) expense increased 76%, to $2.1 billion for the year ended December 31, 2024 from $1.2 billion for the year ended December 31, 2023, and increased 8% on an equivalent basis per Boe. Subsequent to December 31, 2023, we invested approximately $3.7 billion in the acquisition and development of crude oil and natural gas properties. The increase in total DD&A expense was primarily due to a 63% increase in sales volumes between periods driven by the Hibernia, Tap Rock, and Vencer acquisitions. The increase in DD&A expense per Boe was due to an increase in the depletion rate driven by a greater increase in the depletable property base in proportion to proved reserves.

Transaction costs. During the year ended December 31, 2024, we incurred $31.4 million in legal, advisor, and other costs associated with the Vencer Acquisition and subsequent integration, in addition to our divestiture of certain non-core assets in the DJ Basin. 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, Tap Rock, and Vencer acquisitions. Refer to “*Item 8. Financial Statements and Supplementary Data - Note 2 - Acquisitions and Divestitures*” for additional discussion over our acquisitions.

General and administrative expense. General and administrative expense increased 41%, to $227.0 million for the year ended December 31, 2024, from $161.1 million for the year ended December 31, 2023, and decreased 13% on an equivalent basis per Boe. The increase in general and administrative expense was primarily driven by the growth in headcount and associated costs as a result of the addition of operations in the Permian Basin. General and administrative expense per Boe decreased due to a 63% increase in sales volumes.

Derivative gain. Our derivative gain for the year ended December 31, 2024 was $37.5 million, as compared to a gain of $9.3 million for the year ended December 31, 2023. Our derivative gain for the year ended December 31, 2024 was due to fair market value adjustments resulting from lower market prices relative to our open positions and cash settlement net gains. Our derivative gain for the year ended December 31, 2023 was due to fair market value adjustments resulting from lower market prices relative to our open positions, partially offset by cash settlement losses. Refer to “*Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives*” for additional discussion.

Interest expense. Interest expense for the years ended December 31, 2024 and 2023 was $456.3 million and $182.7 million, respectively. The increase in interest expense was attributable to the debt issued in conjunction with the financing of the Hibernia, Tap Rock, and Vencer acquisitions. Average debt outstanding for the years ended December 31, 2024 and 2023 was $4.9 billion and $2.1 billion, respectively. The components of interest expense for the periods presented are as follows (in thousands):

	Year Ended December 31,	
	2024	**2023**
Senior Notes	$ 337,438	$ 154,607
Credit Facility	59,007	12,100
Commitment and letter of credit fees under the Credit Facility	5,493	6,231
Amortization of deferred financing costs and deferred acquisition consideration	52,702	9,293
Other	1,663	509
Total interest expense	$ 456,303	$ 182,740

Income tax expense. Our effective tax rate 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 the effect of state income taxes, excess tax benefits and deficiencies on stock-based compensation awards, tax limitations on compensation of covered individuals, tax credits, and other permanent differences. Refer to "*Item 8. Financial Statements and Supplementary Data - Note 12 - Income Taxes"* for additional discussion.

Our income tax expense for the years ended December 31, 2024 and 2023 was $244.0 million and $215.2 million, resulting in an effective tax rate of 22.5% and 21.5%, respectively, on income from operations before income taxes. During the year ended December 31, 2024, income tax expense was additionally impacted by deferred tax benefits from the state apportionment changes as a result of the Vencer Acquisition. During the year ended December 31, 2023, income tax expense was additionally impacted by deferred tax benefits from state apportionment changes as a result of the Hibernia and Tap Rock acquisitions.

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, the 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, transportation, processing, and refining capacity, regulatory constraints, and other supply chain dynamics, among other factors.

As of December 31, 2024, our liquidity was $1.82 billion, consisting of cash on hand of $75.8 million and $1.75 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. As of February 21, 2025, the available borrowing capacity on our Credit Facility was $1.70 billion. Our Credit Facility is set to mature in August 2028, with the next scheduled borrowing base redetermination date to occur in May 2025.

The Credit Facility contains customary representations and various affirmative and negative covenants as well as certain financial covenants, including (a) a permitted net leverage ratio of not greater than 3.00 to 1.00, (b) a current ratio, inclusive of the unused commitments under the Credit Facility then available to be borrowed, of not less than 1.00 to 1.00, and (c) upon the achievement of investment grade credit ratings, a PV-9 coverage ratio of the net present value, discounted at 9% per annum, of the estimated future net revenues expected in the proved reserves to our total net indebtedness of not less than 1.50 to 1.00 ("PV-9 Coverage Ratio"). We were in compliance with all covenants under the Credit Facility as of December 31, 2024, and through the filing of this Annual Report on Form 10-K. Refer to "*Item 8. Financial Statements and Supplementary Data - Note 5 - Debt*" for additional information.

Our material short-term cash requirements include: operating activities, working capital requirements, capital expenditures, dividends, and payments of contractual obligations, including the payment of the remaining portion of the deferred consideration due with respect to the Vencer Acquisition. 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. 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 financing, 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 2025 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 Annual Report on Form 10-K, and based on current expectations, the long-term.

Sources and Uses of Cash and Cash Equivalents

The following table presents the sources and uses of our cash and cash equivalents for the periods presented (in thousands):

	Activity Type	Year Ended December 31, 2024	2023
Sources of Cash and Cash Equivalents			
Net cash provided by operating activities	Operating	$ 2,865,228	$ 2,238,760
Proceeds from property transactions	Investing	208,824	90,456
Proceeds from credit facility	Financing	1,900,000	2,120,000
Proceeds from issuance of senior notes	Financing	—	3,653,750
Other, net	Investing/ Financing	2,010	459
Total sources of cash and cash equivalents		$ 4,976,062	$ 8,103,425
Uses of Cash and Cash Equivalents			
Acquisitions of businesses, net of cash acquired	Investing	(905,096)	(3,655,612)
Acquisitions of crude oil and natural gas properties	Investing	(47,440)	(154,855)
Capital expenditures for drilling and completion activities and other fixed assets	Investing	(1,924,426)	(1,352,388)
Deposits for acquisitions	Investing	—	(161,250)
Payments to credit facility	Financing	(2,200,000)	(1,370,000)
Dividends paid	Financing	(493,842)	(660,320)
Common stock repurchased and retired	Financing	(427,305)	(320,398)
Other, net	Investing/ Financing	(28,942)	(69,921)
Total uses of cash and cash equivalents		$ (6,027,051)	$ (7,744,744)
Net change in cash and cash equivalents		$ (1,050,989)	$ 358,681

Sources of Cash and Cash Equivalents

Our sources of cash and cash equivalents decreased by $3.1 billion year over year, primarily driven by the 2023 issuances of an aggregate principal amount of $3.7 billion from our 2028 Senior Notes, 2030 Senior Notes, and 2031 Senior Notes. The net cash proceeds from such issuances were used to fund the Hibernia and Tap Rock acquisitions in 2023 and the Vencer Acquisition in 2024.

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 increased by $626.5 million during the year ended December 31, 2024, compared to the year ended December 31, 2023. The increase between periods was primarily due to higher net operating cash flows from the Hibernia, Tap Rock, and Vencer acquisitions. This increase was partially offset by a $371.3 million increase in cash paid for interest and a $411.2 million increase in changes in operating assets and liabilities primarily due to the reduction of (i) $239.6 million in production taxes payable from lower commodity pricing and (ii) $176.0 million in crude oil and natural gas revenue distributions payable primarily as a result of the full integration of the Hibernia and Tap Rock acquisitions into our systems and processes. See "*Results of Operations*" above for more information on the factors driving these changes.

Uses of Cash and Cash Equivalents

Our uses of cash and cash equivalents decreased by $1.7 billion year over year, primarily driven by the 2023 Hibernia and Tap Rock acquisitions for $3.7 billion, partially offset by $905.1 million for acquisitions in 2024 mainly related to the Vencer Acquisition. In addition, cash and cash equivalents used to pay dividends decreased by $166.5 million during the year ended December 31, 2024, as dividends declared and paid decreased from $7.60 per share in 2023 to $4.97 per share in 2024 largely attributable to a decrease in Adjusted Free Cash Flow for the preceding twelve-month period, as well as our decision to adjust the return of capital allocation beginning in the third quarter of 2024. This decision contributed, in part, to a

$106.9 million increase in common stock repurchased and retired during the year ended December 31, 2024, compared to the year ended December 31, 2023.

The above described net decrease was partially offset by $830.0 million of increased payments to our Credit Facility in 2024 in connection with our efforts to pay down debt following the draws made in late 2023 to partially fund the Vencer Acquisition. Lastly, capital expenditures for drilling and completion activities and other fixed assets increased by $572.0 million, largely attributable to a full year of operating assets acquired in the Hibernia and Tap Rock acquisitions, as well as the Vencer Acquisition completed in early 2024. During 2024, we drilled, completed, and turned to sales 114.0, 123.3, and 107.6 net operated wells, respectively, in the Permian Basin, and 75.1, 82.8, and 103.9 net operated wells, respectively, in the DJ Basin. During 2023, we drilled, completed, and turned to sales 44.3, 48.9, and 66.7 net operated wells, respectively, in the Permian Basin, and 90.6, 107.8, and 124.3 net operated wells, respectively, in the DJ Basin.

Non-GAAP Financial Measures

Reconciliation of Net Income to Adjusted EBITDAX

Adjusted EBITDAX is a supplemental non-GAAP financial measure that 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. We present Adjusted EBITDAX 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. 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 for the periods presented (in thousands):

	Year Ended December 31,	
	2024	2023
Net income	$ 838,723	$ 784,288
Exploration	14,322	2,178
Depreciation, depletion, and amortization	2,056,427	1,171,192
Unused commitments[1]	1,730	5,013
Transaction costs	31,419	84,328
Stock-based compensation[2]	48,272	34,931
Derivative gain, net	(37,490)	(9,307)
Derivative cash settlement gain (loss), net	6,435	(68,246)
Interest expense	456,303	182,740
Interest income[3]	(11,058)	(33,347)
Loss on property transactions, net	2,566	254
Income tax expense	243,972	215,166
Adjusted EBITDAX	$ 3,651,621	$ 2,369,190

(1) Included as a portion of other operating expense in the accompanying consolidated statements of operations.

(2) Included as a portion of general and administrative expense in the accompanying consolidated statements of operations.

(3) Included as a portion of other income in the accompanying consolidated statements of operations.

Reconciliation of Cash Provided by Operating Activities to Adjusted Free Cash Flow

Adjusted 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 Adjusted Free Cash Flow provides additional information that may be useful to investors and analysts 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. Adjusted 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 Adjusted Free Cash Flow for the periods presented (in thousands):

	Year Ended December 31,	
	2024	2023
Net cash provided by operating activities	$ 2,865,228	$ 2,238,760
Add back: Changes in operating assets and liabilities, net	339,264	(71,932)
Cash flow from operations before changes in operating assets and liabilities	3,204,492	2,166,828
Less: Cash paid for capital expenditures for drilling and completion activities and other fixed assets	(1,924,426)	(1,352,388)
Less: Changes in working capital related to capital expenditures	(8,208)	(12,349)
Capital expenditures	(1,932,634)	(1,364,737)
Less: Purchases of carbon credits and renewable energy credits	(5,744)	(6,151)
Adjusted Free Cash Flow	$ 1,266,114	$ 795,940

Reconciliation of Standardized Measure to Proved Reserves PV-10

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,		
	2024	2023	2022
Standardized Measure	$ 8,315.4	$ 8,269.3	$ 7,927.5
Present value of future income taxes discounted at 10%	899.9	1,110.7	1,906.8
PV-10	$ 9,215.3	$ 9,380.0	$ 9,834.3

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 accompanying consolidated statements 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,	
	2024	2023
Average crude oil sales price (per Bbl)	$ 75.26	$ 75.57
Effects of derivatives, net (per Bbl) [(1)]	(0.72)	(1.62)
Average crude oil sales price (after derivatives) (per Bbl)	$ 74.54	$ 73.95
Average natural gas sales price (per Mcf)	$ 0.77	$ 2.28
Effects of derivatives, net (per Mcf) [(1)]	0.22	(0.06)
Average natural gas sales price (after derivatives) (per Mcf)	$ 0.99	$ 2.22
Average NGL sales price (per Bbl)	$ 21.09	$ 21.35
Effects of derivatives, net (per Bbl) [(1)]	—	—
Average NGL sales price (after derivatives) (per Bbl)	$ 21.09	$ 21.35

(1) Derivatives economically hedge the price we receive for crude oil, natural gas, and NGL. For the year ended December 31, 2024, the derivative cash settlement loss for crude oil was $41.7 million and the derivative cash settlement gain for natural gas was $48.1 million. 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. We did not hedge the price we received for NGL during the periods presented. Refer to "*Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives*" of this Annual Report on Form 10-K 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 crude 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.

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 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 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 the 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 an independent third-party reserve engineering firm, Ryder Scott, to audit 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, 2024, 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 29.7 MMBoe or 4%. The reserve decrease would have increased our DD&A rate by $0.64 per Boe and decreased our pre-tax income by $81.0 million for the year ended December 31, 2024. This estimated impact is based on available data as of December 31, 2024, and future events could require different adjustments to our DD&A rate. There were no impairment charges recognized related to our proved and unproved properties during the years ended December 31, 2024 or 2023. For more information regarding reserve estimations, including additional 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 2024, we accounted for one business combination under the acquisition method of accounting, the Vencer 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 $2.1 billion for the Vencer 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 Vencer of $2.0 billion 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 3.0% in 2024, 4.1% in 2023, and 8.0% in 2022. While we experience cost inflation on labor, power, and other key costs in our operations and development program, we do not believe it had a material impact on our results of operations for the periods ended December 31, 2024, 2023, or 2022.

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 crude oil and natural gas properties, asset retirement obligations, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of crude oil and natural 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 impact the supply and demand for crude oil and 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 4% and our PV-10 value as of December 31, 2024 would decrease by approximately 19% or $1.8 billion. If crude oil and natural gas SEC prices increased by 10%, our proved reserve volumes would increase by 3% and our PV-10 value as of December 31, 2024 would increase by approximately 20% or $1.8 billion.

PV-10 is a non-GAAP financial measure. 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 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, and basis protection swaps. 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 as of December 31, 2024, a hypothetical upward or downward shift of 10% in the forward curve for the related indices would decrease our derivative gain by $86.7 million or increase it by $183.4 million, respectively. Refer to "*Item 8. Financial Statements and Supplementary Data - Note 9 - Derivatives*" for summary derivative activity tables.

Interest Rates

As of December 31, 2024 and February 21, 2025, we had $450.0 million and $800.0 million, respectively, outstanding under our Credit Facility. Borrowings under our Credit Facility bear interest at a fluctuating rate that is tied to, at our option, the Alternate Base Rate ("ABR") or Secured Overnight Financing Rate ("SOFR"), plus the applicable margin. Any increases in these interest rates can have an adverse impact on our results of operations and cash flows. As of December 31, 2024, and through the filing date of this Annual Report on Form 10-K, we were in compliance with all financial and non-financial covenants under the Credit Facility.

Counterparty and Customer Credit Risk

We are exposed to counterparty credit risk associated with our derivative activities. As of December 31, 2024 and February 21, 2025, our derivative contracts have been executed with 16 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 the 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, 2024.

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, 2024 and 2023, the related consolidated statements of operations, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, 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, 2024, based on criteria established in I*nternal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2025, 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 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 audit management's estimates of crude 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 audit the estimated 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 certain crude oil and natural gas assets from Vencer Energy, LLC ("Vencer") in an acquisition accounted for as a business combination, 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 acquisition of certain crude oil and natural gas assets from Vencer 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 24, 2025

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,	
	2024	**2023**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 75,826	$ 1,124,797
Accounts receivable, net:		
Crude oil and natural gas sales	646,290	505,961
Joint interest and other	125,047	247,228
Derivative assets	66,517	35,192
Deposits for acquisitions	—	163,164
Prepaid expenses and other	74,638	68,070
Total current assets	988,318	2,144,412
Property and equipment (successful efforts method):		
Proved properties	16,897,070	12,738,568
Less: accumulated depreciation, depletion, and amortization	(4,287,752)	(2,339,541)
Total proved properties, net	12,609,318	10,399,027
Unproved properties	630,727	821,939
Wells in progress	505,556	536,858
Other property and equipment, net of accumulated depreciation of $9,382 in 2024 and $9,808 in 2023	48,757	62,392
Total property and equipment, net	13,794,358	11,820,216
Derivative assets	17,037	8,233
Other noncurrent assets	144,407	124,458
Total assets	$ 14,944,120	$ 14,097,319
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 560,893	$ 565,708
Production taxes payable	322,976	421,045
Crude oil and natural gas revenue distribution payable	702,130	766,123
Derivative liability	22,178	18,096
Deferred acquisition consideration	478,749	—
Other liabilities	118,168	80,915
Total current liabilities	2,205,094	1,851,887
Long-term liabilities:		
Debt, net	4,493,531	4,785,732
Ad valorem taxes	294,058	307,924
Derivative liability	13,016	—
Deferred income tax liabilities, net	800,554	564,781
Asset retirement obligations	399,002	305,716
Other long-term liabilities	110,119	99,958
Total liabilities	8,315,374	7,915,998
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, 93,933,857 and 93,774,901 issued and outstanding as of December 31, 2024 and 2023, respectively	5,006	5,004
Additional paid-in capital	5,095,298	4,964,450
Retained earnings	1,528,442	1,211,867
Total stockholders' equity	6,628,746	6,181,321
Total liabilities and stockholders' equity	$ 14,944,120	$ 14,097,319

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,		
	2024	**2023**	**2022**
Operating net revenues:			
Crude oil, natural gas, and NGL sales	$ 5,202,408	$ 3,473,821	$ 3,787,584
Other operating income	4,400	5,419	3,814
Total operating net revenues	5,206,808	3,479,240	3,791,398
Operating expenses:			
Lease operating expense	577,837	301,288	169,986
Midstream operating expense	48,038	45,080	31,944
Gathering, transportation, and processing	377,678	290,645	287,474
Severance and ad valorem taxes	377,388	276,535	305,701
Exploration	14,322	2,178	6,981
Depreciation, depletion, and amortization	2,056,427	1,171,192	816,446
Abandonment and impairment of unproved properties	—	—	17,975
Transaction costs	31,419	84,328	24,683
General and administrative expense	226,965	161,077	143,477
Other operating expense	17,330	7,437	2,691
Total operating expenses	3,727,404	2,339,760	1,807,358
Other income (expense):			
Derivative gain (loss), net	37,490	9,307	(335,160)
Interest expense	(456,303)	(182,740)	(32,199)
Gain (loss) on property transactions, net	(2,566)	(254)	15,880
Other income	24,670	33,661	21,217
Total other expense	(396,709)	(140,026)	(330,262)
Income from operations before income taxes	1,082,695	999,454	1,653,778
Income tax expense	(243,972)	(215,166)	(405,698)
Net income	$ 838,723	$ 784,288	$ 1,248,080
Earnings per common share			
Basic	$ 8.48	$ 9.09	$ 14.68
Diluted	$ 8.46	$ 9.02	$ 14.58
Weighted-average common shares outstanding:			
Basic	98,865	86,240	85,005
Diluted	99,176	86,988	85,604

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, 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
Dividends declared, $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
Dividends declared, $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
Issuance pursuant to acquisition	7,181,527	72	488,846	—	488,918
Restricted common stock issued	456,890	4	—	—	4
Stock used for tax withholdings	(167,711)	(1)	(12,036)	—	(12,037)
Exercise of stock options	333	—	10	—	10
Common stock repurchased and retired	(7,312,083)	(73)	(394,244)	(32,988)	(427,305)
Stock-based compensation	—	—	48,272	—	48,272
Dividends declared, $4.97 per share	—	—	—	(489,160)	(489,160)
Net Income	—	—	—	838,723	838,723
Balances, December 31, 2024	93,933,857	$ 5,006	$ 5,095,298	$ 1,528,442	$ 6,628,746

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,		
	2024	**2023**	**2022**
Cash flows from operating activities:			
Net income	$ 838,723	$ 784,288	$ 1,248,080
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, and amortization	2,056,427	1,171,192	816,446
Abandonment and impairment of unproved properties	—	—	17,975
Stock-based compensation	48,272	34,931	31,367
Derivative (gain) loss, net	(37,490)	(9,307)	335,160
Derivative cash settlement gain (loss), net	6,435	(68,246)	(576,802)
Amortization of deferred financing costs and deferred acquisition consideration	52,702	9,293	4,464
(Gain) loss on property transactions, net	2,566	254	(15,880)
Deferred income tax expense	235,773	245,163	337,502
Other, net	1,084	(740)	2,588
Changes in operating assets and liabilities, net			
Accounts receivable, net	(23,036)	(39,869)	(941)
Prepaid expenses and other	(17,644)	19,987	(34,025)
Accounts payable, accrued expenses, and other liabilities	(298,584)	91,814	311,107
Net cash provided by operating activities	2,865,228	2,238,760	2,477,041
Cash flows from investing activities:			
Acquisitions of businesses, net of cash acquired	(905,096)	(3,655,612)	(236,160)
Acquisitions of crude oil and natural gas properties	(47,440)	(154,855)	(97,453)
Deposits for acquisitions	—	(161,250)	—
Capital expenditures for drilling and completion activities and other fixed assets	(1,924,426)	(1,352,388)	(967,096)
Proceeds from property transactions	208,824	90,456	1,776
Purchases of carbon credits and renewable energy credits	(5,744)	(6,151)	(7,298)
Other, net	2,000	(3,355)	136
Net cash used in investing activities	(2,671,882)	(5,243,155)	(1,306,095)
Cash flows from financing activities:			
Proceeds from credit facility	1,900,000	2,120,000	100,000
Payments to credit facility	(2,200,000)	(1,370,000)	(100,000)
Proceeds from issuance of senior notes	—	3,653,750	—
Payment of deferred financing costs and other	(7,724)	(45,788)	(1,174)
Redemption of senior notes	—	—	(100,000)
Dividends paid	(493,842)	(660,320)	(536,922)
Common stock repurchased and retired	(427,305)	(320,398)	—
Payment of employee tax withholdings in exchange for the return of common stock	(12,037)	(13,416)	(19,580)
Other, net	(3,427)	(752)	308
Net cash provided by (used in) financing activities	(1,244,335)	3,363,076	(657,368)
Net change in cash, cash equivalents, and restricted cash	(1,050,989)	358,681	513,578
Cash, cash equivalents, and restricted cash:			
Beginning of period [1]	1,126,815	768,134	254,556
End of period [1]	$ 75,826	$ 1,126,815	$ 768,134

[1] Includes restricted cash consisting of $1.9 million of interest earned on cash held in escrow that is presented in deposits for acquisitions 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 consolidated balance sheets for the period ended December 31, 2023 and 2022.

Refer to *Note 2 - Acquisitions and Divestitures and Note 14 - Supplemental Disclosures of Cash Flow Information* for additional 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 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 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, 2024, through the filing date of this report. Additionally, certain insignificant prior period 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 our consolidated financial statements requires us to make various assumptions, judgments, and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of commitments and contingencies. Changes in these assumptions, judgments, and estimates will occur as a result of the passage of time and the occurrence of future events. Accordingly, actual results could differ from amounts previously estimated. Additionally, the prices received for crude oil, natural gas, and NGL production can heavily influence our assumptions, judgments and estimates, and continued volatility of crude oil and natural gas prices could have a significant impact on our estimates.

The more significant areas requiring the use of assumptions, judgments, and estimates include: (i) crude oil and natural gas reserves; (ii) cash flow estimates used in impairment tests for long-lived assets; (iii) depreciation, depletion and amortization; (iv) determining fair value and allocating purchase price in connection with business combinations and asset acquisitions; (v) accrued revenues and related receivables; (vi) accrued liabilities; (vii) derivative valuations; (viii) asset retirement obligations; (ix) deferred income taxes; and (i) determining the fair values of certain stock-based compensation awards.

Industry Segment and Geographic Information

We report our operations in one reportable upstream segment, which is engaged in the acquisition, development, and production of crude oil and associated liquids-rich natural gas in the DJ Basin in Colorado and the Permian Basin in Texas and New Mexico. The DJ Basin and the Permian Basin are operating segments of the Company that we aggregate into the upstream segment due to the similar nature of these operations that are solely focused in the U.S. Refer to *Note 16 - Segment Reporting* for additional information.

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, 2024 and 2023, 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 10% or more of our total crude oil, natural gas and NGL sales for at least one of the periods as follows:

	Year Ended December 31,		
	2024	2023	2022
Purchaser A	15 %	5 %	— %
Purchaser B	10 %	28 %	50 %
Purchaser C	10 %	16 %	6 %
Purchaser D	1 %	1 %	12 %

Property and Equipment

Proved Properties. We account for our crude 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. We group our crude oil and natural gas properties with a common geological structure or stratigraphic condition for purposes of computing units-of-production depletion. During the years ended December 31, 2024, 2023, and 2022, we incurred depletion expense of $2.0 billion, $1.1 billion, and $773.5 million, respectively.

We assess proved properties for impairment using the same units of account utilized in the determination of units-of production depletion 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 is usually 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, 2024 and 2023, the net book value of our midstream assets in the accompanying consolidated balance sheets was $406.9 million and $339.9 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, 2024, 2023, and 2022, we incurred depreciation expense on our midstream assets of $15.0 million, $12.3 million, and $10.8 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 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 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 the 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 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 an independent third-party reserve engineering firm, Ryder Scott, to audit 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 two 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 consolidated 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. 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 credits are initially capitalized at cost as an intangible asset within other noncurrent assets on the accompanying consolidated balance sheets. Subsequently, the credits are expensed when applied to our greenhouse gas emissions through depletion, depreciation, and amortization expense on the accompanying consolidated statements of operations. Purchased credits expected to be utilized within the next 12 months are presented as short-term within prepaid expenses and other on the accompanying consolidated balance sheets.

Deferred Financing Costs

Deferred financing costs include origination, legal, and other fees incurred to issue senior notes or amend our Credit Facility. Deferred financing costs related to the Credit Facility are capitalized to prepaid expenses and other and other noncurrent assets on the accompanying consolidated balance sheets and amortized to interest expense on the accompanying consolidated 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 debt, net on the accompanying consolidated balance sheets and amortized to interest expense on the accompanying consolidated 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 recognized 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 consolidated 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 consolidated statements of cash flows. Refer to *Note 10 - Asset Retirement Obligations* for a reconciliation of our total asset retirement obligation liability as of December 31, 2024 and 2023.

Environmental Liabilities

We are subject to federal, state, and local environmental laws and regulations. These laws regulate the release, disposal, or discharge of materials into the environment or otherwise relate to environmental protection and may require us to remove or mitigate the environmental effects of the discharge, disposal, or release of hydrocarbons at various sites. Liabilities for future expenditures, including any associated with acquired assets, are recorded when environmental assessments and/or remediation arising outside of normal operations of the asset is probable and the costs can be reasonably estimated. Environmental liabilities are recorded in accounts payable and accrued expenses in our accompanying consolidated balance sheet and expensed within lease operating expense in our accompanying consolidated statement of operations.

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, and basis protection swaps. The crude oil instruments are indexed to NYMEX WTI prices, and natural gas instruments are indexed to NYMEX HH and Waha prices, all of which have a high degree of historical correlation with actual prices received by, before differentials. As of December 31, 2024, 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 consolidated 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 consolidated statements of operations as they occur.

As of December 31, 2024 and 2023, 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 consolidated balance sheets.

Derivative (gain) loss, net as well as derivative cash settlement gain (loss), net are included within the cash flows from operating activities section of the accompanying consolidated statements of cash flows. 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 consolidated 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 consolidated 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 consolidated 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 consolidated 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 natural gas residue 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 transaction 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 one to two months 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. 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. 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. 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. 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 consolidated 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. 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 - 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 - 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. 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. We adopted this ASU on October 1, 2024, and applied the amendments retrospectively to all prior periods presented in our consolidated financial statements. Refer to *Note 16 - Segment Reporting* for additional discussion.

In December 2023, the FASB issued ASU No. 2023-09, Improvements to Income Tax Disclosures ("ASU 2023-09"). ASU 2023-09 is intended to enhance income tax disclosures by requiring disclosure of items such as the disaggregation of the income tax rate reconciliation as well as information regarding income taxes paid. 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.

In March 2024, the SEC adopted rules intended to enhance and standardize climate-related disclosures in registration statements and annual reports. The new rules will require disclosure of material climate-related risks, including disclosure of boards of directors' oversight and risk management activities, the material impacts of these risks to us and the quantification of material impacts to us as a result of severe weather events and other natural conditions. The rules also require disclosure of material greenhouse gas emissions and any material climate-related targets and goals. The new rules were to be effective for annual reporting periods beginning in fiscal year 2025, except for the greenhouse gas emissions disclosures which were to be effective for annual reporting periods beginning in fiscal year 2026, though the new rules were voluntarily stayed by the SEC on April 4, 2024 pending completion of the judicial review of consolidated challenges to the new rules by the Court of Appeals for the Eighth Circuit. We are continuing to monitor the status of these new rules.

In November 2024, the FASB issued ASU No. 2024-03, Disaggregation of Income Statement Expenses ("ASU 2024-03"). ASU 2024-03 requires public entities to disclose disaggregated information about certain costs and expenses. This ASU is effective for annual reporting periods beginning after December 15, 2026, and early adoption is permitted. ASU 2024-03 should be applied on a prospective basis, and retrospective application is permitted. We are evaluating the impact that ASC 2024-03 will have on the consolidated financial statements and our plan for adoption, including the adoption date and transition method.

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, 2024, 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.

Vencer Acquisition

On January 2, 2024, we completed the acquisition of certain crude oil and natural gas assets from Vencer for adjusted aggregate consideration of approximately $2.0 billion, inclusive of customary post-closing adjustments and $550.0 million in cash to be paid on or before January 3, 2025. In connection with and upon execution of the Vencer purchase and sale agreement, we deposited cash of $161.3 million with an escrow agent. This deposit, along with interest accrued thereon, was credited against the cash payable at closing. The following tables present the consideration transferred and the final purchase price allocation of the assets acquired and the liabilities assumed in the Vencer Acquisition:

Consideration (in thousands, except shares and per share amount)		
Cash consideration	$	996,420
Deferred acquisition consideration[(1)(3)]	$	532,284
Shares of common stock issued		7,181,527
Closing price per share[(2)]	$	68.08
Equity consideration[(4)]	$	488,918
Total consideration	$	2,017,622

(1) Based on discounted fixed and determinable future payments of cash.

(2) Based on the closing stock price of Civitas common stock on January 2, 2024.

(3) Amounts represent non-cash investing activities until such time payments are made, as applicable. Refer to *Note 5 - Debt* for additional information.

(4) Amounts represent non-cash financing activities.

Final Purchase Price Allocation (in thousands)		
Assets Acquired		
Proved properties	$	1,858,909
Unproved properties		231,627
Other property and equipment		666
Right-of-use assets		4,049
Total assets acquired	$	2,095,251
Liabilities Assumed		
Accounts payable and accrued expenses	$	5,000
Crude oil and natural gas revenue distribution payable		28,423
Asset retirement obligations		40,157
Lease liability		4,049
Total liabilities assumed		77,629
Net assets acquired	$	2,017,622

The purchase price allocation for the Vencer Acquisition was finalized as of the fourth quarter of 2024 with immaterial adjustments made to the preliminary allocation initially presented in the Quarterly Report on Form 10-Q for the quarter ended March 31, 2024, filed with the SEC on May 2, 2024.

Hibernia Acquisition

On August 2, 2023, we acquired all of the issued and outstanding equity ownership interests of Hibernia Energy III (“, LLC (“HE3”) and Hibernia Energy III-B, LLC (“HE3-B” and, together with HE3, “Hibernia”) for aggregate consideration of approximately $2.2 billion in cash, inclusive of customary post-closing adjustments (the “Hibernia Acquisition”). The following table presents the final purchase price allocation of the assets acquired and the liabilities assumed in the Hibernia Acquisition:

Final Purchase Price Allocation (in thousands)		
Assets Acquired		
Cash and cash equivalents	$	30,671
Accounts receivable - crude oil and natural gas sales		86,262
Accounts receivable - joint interest and other		4,463
Proved properties		2,150,872
Unproved properties		115,802
Other property and equipment		520
Right-of-use assets		30,393
Total assets acquired	$	2,418,983
Liabilities Assumed		
Accounts payable and accrued expenses	$	110,022
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		234,301
Net assets acquired	$	2,184,682

The purchase price allocation for the Hibernia Acquisition was finalized as of the third quarter of 2024 with immaterial adjustments made to the preliminary allocation initially presented in the Quarterly Report on Form 10-Q for the quarter ended September 30, 2023, filed with the SEC on November 7, 2023.

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 AcquisitionCo”), Tap Rock Resources II, LLC (“Tap Rock Resources II”), and Tap Rock NM10 Holdings, LLC (“Tap Rock NM10” and, together with Tap Rock AcquisitionCo and Tap Rock NM10, “Tap Rock”) for aggregate consideration of approximately $2.5 billion, inclusive of customary post-closing adjustments (the “Tap Rock Acquisition”). The following tables present the consideration transferred and final purchase price allocation of the assets acquired and the liabilities assumed in the Tap Rock Acquisition:

Consideration (in thousands, except shares and per share amount)		
Cash consideration	$	1,502,880
Shares of common stock issued		13,538,472
Closing price per share[(1)]	$	73.14
Equity consideration	$	990,204
Total consideration	$	2,493,084

(1) Based on the closing stock price of Civitas common stock on August 2, 2023.

Final Purchase Price Allocation (in thousands)

Assets Acquired		
Cash and cash equivalents	$	6,543
Accounts receivable - crude oil and natural gas sales		105,509
Accounts receivable - joint interest and other		30,415
Prepaid expenses and other		17,930
Proved properties		2,334,678
Unproved properties		300,859
Other property and equipment		12,827
Right-of-use assets		626
Total assets acquired	$	2,809,387
Liabilities Assumed		
Accounts payable and accrued expenses	$	157,606
Production taxes payable		9,692
Crude oil and natural gas revenue distribution payable		68,094
Ad valorem taxes		1,407
Asset retirement obligations		28,612
Lease liability		626
Deferred revenue		50,266
Total liabilities assumed		316,303
Net assets acquired	$	2,493,084

The purchase price allocation for the Tap Rock Acquisition was finalized as of the third quarter of 2024 with immaterial adjustments made to the preliminary allocation initially presented in the Quarterly Report on Form 10-Q for the quarter ended September 30, 2023, filed with the SEC on November 7, 2023.

Revenue and earnings of the acquiree

The results of operations for the Vencer Acquisition since the closing date have been included in our consolidated financial statements during the year ended December 31, 2024. The amount of revenue of Vencer included in our accompanying consolidated statements of operations was approximately $769.5 million during the year ended December 31, 2024. We determined that disclosing the amount of Vencer-related net income included in the accompanying statements of operations is impracticable as the operations from the acquisition were integrated into our operations from the date of the acquisition.

Supplemental unaudited pro forma financial information

The results of operations for the Vencer, Hibernia, and Tap Rock acquisitions since their respective closing dates have been included in our consolidated financial statements and therefore do not require pro forma disclosure for the year ended December 31, 2024. 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 Vencer Acquisition had been completed as of January 1, 2023 and the Hibernia and Tap Rock acquisitions 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 Vencer, Hibernia, and Tap Rock acquisitions had been effective as of those dates, or of future results, and includes certain nonrecurring pro forma adjustments that were directly related to these business combinations.

	Year Ended December 31, 2023	Year Ended December 31, 2022
Total revenue	$ 5,263,500	$ 5,808,411
Net income	1,242,062	1,821,139
Earnings per common share - basic	$ 12.25	$ 18.48
Earnings per common share - diluted	12.16	18.37

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 consolidated statements of operations. Transaction costs also include costs associated with our divestiture of certain non-core assets in the DJ Basin, completed in early 2024. We incurred transaction costs of $31.4 million, $84.3 million, and $24.7 million during the years ended December 31, 2024, 2023, and 2022, respectively.

NOTE 3 - REVENUE RECOGNITION

Crude oil, natural gas, and NGL sales revenue presented within the accompanying consolidated 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):

Sales by Commodity and Operating Region	Year Ended December 31, 2024	2023	2022
Crude oil			
DJ Basin	$ 2,004,176	$ 2,140,608	$ 2,535,496
Permian Basin	2,362,932	634,756	—
Total	4,367,108	2,775,364	2,535,496
Natural gas			
DJ Basin	225,176	280,579	691,903
Permian Basin	(56,788)	25,050	—
Total	168,388	305,629	691,903
NGL			
DJ Basin	341,053	326,675	560,185
Permian Basin	325,859	66,153	—
Total	666,912	392,828	560,185
Crude oil, natural gas, and NGL			
DJ Basin	2,570,405	2,747,862	3,787,584
Permian Basin	2,632,003	725,959	—
Total	$ 5,202,408	$ 3,473,821	$ 3,787,584

We record revenue in the month production is delivered to the purchaser. However, purchaser statements may not be received for one to two months after the date production is delivered, and as a result, we estimate the volume of production delivered to the purchaser and the price that will be received for the sale of the product. Generally, we record the differences between our estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between our revenue estimates and actual revenue received historically have not been significant. For the years ended December 31, 2024, 2023, and 2022 revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

As of December 31, 2024 and December 31, 2023, our receivables from contracts with customers were $646.3 million and $506.0 million, respectively.

NOTE 4 - ACCOUNTS PAYABLE AND ACCRUED EXPENSES

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

	As of December 31, 2024	2023
Accounts payable trade	$ 35,437	$ 55,750
Accrued drilling and completion costs	157,728	149,520
Accrued crude oil and natural gas operating expense	160,253	149,483
Accrued general and administrative expense	36,946	30,095
Accrued transaction costs	—	8,796
Accrued interest expense	135,628	141,401
Other accrued expenses	34,901	30,663
Total accounts payable and accrued expenses	$ 560,893	$ 565,708

NOTE 5 - DEBT

Debt, net of unamortized discounts and deferred financing costs, consists of the following (in thousands):

	As of December 31,	
	2024	2023
Outstanding principal balances on Senior Notes:		
2026 Senior Notes (5.000%)	$ 400,000	$ 400,000
2028 Senior Notes (8.375%)	1,350,000	1,350,000
2030 Senior Notes (8.625%)	1,000,000	1,000,000
2031 Senior Notes (8.750%)	1,350,000	1,350,000
Outstanding principal balances on Senior Notes, gross	4,100,000	4,100,000
Less: unamortized discount and deferred financing costs	(56,469)	(64,268)
Outstanding principal balances on Senior Notes, net	4,043,531	4,035,732
Outstanding balance on Credit Facility	450,000	750,000
Long-term debt	4,493,531	4,785,732
Deferred acquisition consideration	478,749	—
Total debt	$ 4,972,280	$ 4,785,732

Senior Notes

The table below summarizes the face values, interest rates, maturity dates, and semi-annual interest payment dates related to our outstanding senior note obligations as of December 31, 2024 (in thousands):

	Interest Rate	Interest Payment Dates	Principal Amount	Maturity Date
2026 Senior Notes	5.000%	April 15, October 15	$ 400,000	October 15, 2026
2028 Senior Notes	8.375%	January 1, July 1	1,350,000	July 1, 2028
2030 Senior Notes	8.625%	May 1, November 1	1,000,000	November 1, 2030
2031 Senior Notes	8.750%	January 1, July 1	1,350,000	July 1, 2031

The 2026 Senior Notes, 2028 Senior Notes, 2030 Senior Notes, and 2031 Senior Notes (collectively, the "Senior Notes") are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. The Company may redeem some or all of its Senior Notes prior to their maturity at redemption prices that may include a premium, plus accrued and unpaid interest as described in the indentures governing the Senior Notes. 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 as of December 31, 2024 and through the filing of this Annual Report on Form 10-K. The indentures governing the Senior Notes also contain customary events of default.

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"), pursuant to an indenture 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 were used to fund 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"), pursuant to an indenture 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"), pursuant to an indenture among us, Computershare Trust Company, N.A., as trustee, and the guarantors party thereto. 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 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% on or after July 1, 2027, 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"), pursuant to an indenture among us, Wells Fargo Bank, National Association, as trustee, and the guarantors party thereto.

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

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").

On June 12, 2024, we entered into a Sixth Amendment to our Credit Agreement (the "Sixth Amendment"), which, among other things, amended certain terms of the Credit Agreement to: (i) increase the borrowing base by $400.0 million for a new borrowing base of $3.4 billion, (ii) increase the aggregate elected commitments by $350.0 million for a new aggregate elected commitment of $2.2 billion, (iii) lower the interest rate margins applicable to loans under the Credit Agreement, (iv) add provisions to lower the interest rate margins and modify certain covenants in the Credit Agreement, as well as to make the Credit Facility unsecured, upon the achievement of investment grade credit ratings, (v) modify certain definitions in the Credit Agreement in connection with the transactions contemplated by the Sixth Amendment, and (vi) provide for the addition of certain new lenders under the Credit Agreement.

As of December 31, 2024, the borrowing base and aggregate elected commitments under the Credit Agreement were $3.4 billion and $2.2 billion, respectively. On February 21, 2025, we amended our Credit Facility to increase our aggregate elected commitments from $2.2 billion to $2.5 billion. The borrowing base of $3.4 billion remained unchanged. The next scheduled borrowing base redetermination date is in May 2025.

Interest and commitment fees associated with the Credit Facility are accrued based on a revolving loan commitment utilization grid set forth in the Credit Agreement. Borrowings under the Credit Facility bear interest at a per annum rate equal to, at our option, either (i) the ABR plus the applicable margin, or (ii) the term-specific SOFR plus the applicable margin. ABR is established as a rate per annum equal to the greatest of (a) the rate of interest publicly announced by JPMorgan as its prime rate, (b) the applicable rate of interest published by the Federal Reserve Bank of New York plus 0.5%, or (c) the term-specific SOFR for an interest period of one month plus 1.0%, in each case, subject to a 1.5% floor, plus an applicable margin of 0.75% to 1.75% 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 an applicable margin of 1.75% to 2.75%, 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.

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, 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, including the suspension and/or modification of certain covenants in the event that we receive investment grade credit ratings, 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) changes to organizational documents, (xii) use of proceeds from loans and letters of credit, (xiii) hedging transactions, (xiv) additional subsidiaries, (xv) changes in fiscal year or fiscal quarter, (xvi) prepayments of certain debt and other obligations, (xvii) sales or discounts of receivables, and (xviii) dividend payment thresholds.

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) a maximum ratio of our consolidated net 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, (b) a current ratio, inclusive of the unused commitments under the Credit Facility then available to be borrowed, to not be less than 1.00 to 1.00, and (c) upon the achievement of investment grade credit ratings, a PV-9 Coverage Ratio. We were in compliance with all covenants under the Credit Facility as of December 31, 2024 and through the filing of this Annual Report on Form 10-K.

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

	February 21, 2025	December 31, 2024	December 31, 2023
Outstanding balance	$ 800,000	$ 450,000	$ 750,000
Letters of credit	2,100	2,100	2,100
Available borrowing capacity	1,697,900	1,747,900	1,097,900
Total aggregate elected commitments	$ 2,500,000	$ 2,200,000	$ 1,850,000

As of December 31, 2024 and 2023, the unamortized deferred financing costs associated with amendments to the Credit Facility were $29.4 million and $34.4 million, respectively. Of the unamortized deferred financing costs, (i) $21.2 million and $26.9 million are presented within other noncurrent assets on the accompanying consolidated balance sheets as of December 31, 2024 and 2023, respectively, and (ii) $8.2 million and $7.5 million are presented within prepaid expenses and other on the accompanying consolidated balance sheets as of December 31, 2024 and 2023, respectively.

Deferred Acquisition Consideration

The Vencer Acquisition included deferred consideration of $550 million to be paid in cash on or before January 3, 2025. We discounted this obligation and recorded $532.3 million as deferred acquisition consideration upon closing and are amortizing the discount to interest expense in the accompanying statements of operations until the payment is made. During the year ended December 31, 2024, we paid $75 million of this deferred consideration, which is recorded as a cash outflow within the acquisitions of businesses, net of cash acquired in the accompanying consolidated statements of cash flows. The remaining $475.0 million of deferred consideration was paid on January 3, 2025.

Interest Expense

For the years ended December 31, 2024, 2023, and 2022, we incurred interest expense of $456.3 million, $182.7 million, and $32.2 million, respectively. Interest expense for the year ended December 31, 2024 includes $37.1 million related to the amortization of deferred acquisition consideration associated with the Vencer Acquisition.

NOTE 6 - COMMITMENTS AND CONTINGENCIES

Commitments

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 this 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 $60.6 million as of December 31, 2024. 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 Gathering Agreement is a value-based percentage of proceeds sales contract and our financial commitment fluctuates with commodity prices. The aggregate financial commitment fee over the remaining term was $49.8 million as of December 31, 2024. During the year ended December 31, 2024, we recorded $4.7 million in other operating expense in the accompanying consolidated statements of operations based on volume deficiencies relative to the minimum volume commitment. Based on current projections, we may incur approximately $4.0 million in additional shortfall payments under the Gathering Agreement during the remaining term of approximately five years. We are actively engaging alternative strategies to reduce any potential contract deficiencies incurred in future periods.

We are also party to additional individually immaterial agreements that require us to pay fees associated with the minimum volumes over various terms ending in April 2025, regardless of the amount delivered. The aggregate financial commitment fee over the remaining term for these contracts was $7.6 million as of December 31, 2024. We have not and do not expect to incur any deficiency payments.

The minimum annual payments under these agreements for the next five years as of December 31, 2024 are presented below (in thousands):

	Minimum Volume[1]
2025	$ 31,676
2026	25,124
2027	25,470
2028	25,765
2029 and thereafter	10,010
Total	$ 118,045

(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.

Litigation and Legal Items

We are involved in various legal proceedings. We review the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in our best interests. We have provided the necessary estimated accruals in the accompanying consolidated balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, we currently believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations, or liquidity.

NOTE 7 - STOCK-BASED COMPENSATION

Long Term Incentive Plans

In June 2024, in connection with our stockholders' approval at our 2024 annual meeting of stockholders, we adopted the 2024 Long Term Incentive Plan (the "2024 LTIP"), which provides for the issuance of restricted stock units, performance stock units, stock options, and various other forms of awards, and reserved 3,100,000 shares of common stock for issuance under the 2024 LTIP. The 2024 LTIP supersedes and replaces all of our previous long-term incentive plans (the "Prior Plans"), such that awards may not be granted under the Prior Plans subsequent to the adoption of the 2024 LTIP. Awards granted under the Prior Plans will remain subject to the terms and conditions set forth in the applicable Prior Plan. The Prior Plans and 2024 LTIP 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 consolidated statements of operations. The following table outlines the compensation expense recorded by type of award (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Restricted and deferred stock units	$ 28,395	$ 19,502	$ 19,401
Performance stock units	19,877	15,429	11,966
Total stock-based compensation	$ 48,272	$ 34,931	$ 31,367

As of December 31, 2024, 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	$ 34,232	2027
Performance stock units	22,877	2026
Total unrecognized stock-based compensation	$ 57,109	

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 under the 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. RSUs generally vest ratably either over a one, two, or three-year service period on each anniversary following the grant date. RSUs are settled in shares of our common stock shortly after vesting. 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 our Board. 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.

The following table presents the changes in non-vested RSUs and DSUs for the year ended December 31, 2024:

	RSUs and DSUs	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	855,627	$ 66.31
Granted	477,506	64.30
Vested	(317,672)	64.94
Forfeited	(82,559)	66.89
Non-vested, end of year	932,902	$ 65.69

The aggregate grant-date fair value of the RSUs and DSUs granted under the LTIP during the year ended December 31, 2024 was $30.7 million.

Performance Stock Units

We grant market-based performance stock units ("PSUs") to our officers and certain executives under the 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 by March 15 of the following year upon the determination and approval of performance achievement by the Compensation Committee of our Board.

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 change in our stock price over the performance period plus dividends paid. 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 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 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 change of non-vested PSUs for the year ended December 31, 2024:

	PSUs	Weighted-Average Grant-Date Fair Value
Non-vested, beginning of year	472,593	$ 92.08
Granted[1]	270,509	74.55
Additional shares based on performance[2]	59,504	97.45
Vested[2]	(139,218)	91.59
Forfeited	(13,342)	99.71
Non-vested, end of year[1]	650,046	$ 85.23

(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.

(2) Upon completion of the performance period for the PSUs granted in 2021, a performance achievement of 200% or 141%, as applicable, was applied to each of the grants, resulting in a number of shares greater than the target amount of such PSUs vesting and being settled during the year ended December 31, 2024.

The aggregate grant-date fair value of the PSUs granted under the LTIP during the year ended December 31, 2024 was $20.2 million. The performance period for PSUs granted in 2022 ended on December 31, 2024. These PSUs are expected to be released during the first quarter of 2025 with a performance achievement of 46% or 54%, as applicable.

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,		
	2024	2023	2022
Expected term (in years)	3.0	3.0	3.2
Risk-free interest rate	4.5%	3.6% to 5.0%	1.8% to 3.2%
Expected daily volatility	3.0%	3.1% to 3.7%	4.0% to 4.7%

NOTE 8 - FAIR VALUE MEASUREMENTS

We follow authoritative accounting guidance for measuring the fair value of assets and liabilities. 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 table presents our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2024 and 2023 and their classification within the fair value hierarchy (in thousands):

	As of December 31,	
	2024	2023
	Level 2	Level 2
Derivative assets	$ 83,554	$ 43,425
Derivative liabilities	$ 35,194	$ 18,096

Long-Term Debt

The portion of our long-term debt related to our Credit Facility, if any, approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The portion of our long-term debt related to our Senior Notes is recorded at cost, net of any unamortized discount and deferred financing costs. The fair value of our Senior Notes is based on quoted market prices, and as such, is designated as Level 1 within the fair value hierarchy. The following table presents the fair value our Senior Notes as of the dates indicated (in thousands):

		As of December 31, 2024		As of December 31, 2023	
	Nominal Interest	Fair Value	Percent of Par	Fair Value	Percent of Par
2026 Senior Notes	5.000%	$ 394,344	98.6%	$ 389,020	97.3%
2028 Senior Notes	8.375%	1,404,608	104.0%	1,412,559	104.6%
2030 Senior Notes	8.625%	1,048,510	104.9%	1,063,050	106.3%
2031 Senior Notes	8.750%	1,408,091	104.3%	1,433,363	106.2%

Our deferred acquisition consideration was recorded in connection with the Vencer Acquisition using an estimated fair value discount at the time of the transaction based on quoted market prices from our debt as well as other inputs classified as Level 2 within the fair value hierarchy. As of December 31, 2024, the carrying value of the deferred acquisition consideration approximated fair value. Refer to *Note 5 - Debt* for additional information.

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 natural gas properties acquired. Refer to *Note 2 - Acquisitions and Divestitures* for additional information. During the years ended December 31, 2024, 2023, and 2022, we recorded no impairments of proved properties. During the year ended December 31, 2022, we recorded $18.0 million of abandonment and impairment of unproved properties. No abandonment and impairment of unproved properties was recorded for the years ended December 31, 2024 and 2023. 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, and basis protection swaps. As of December 31, 2024, 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. 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.

Basis protection swaps are arrangements that guarantee a price differential 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 pay the counterparty if the price differential is less than the stated terms of the contract.

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

	Year Ended December 31,		
	2024	**2023**	**2022**
Derivative cash settlement gain (loss), net			
Crude oil contracts	$ (41,696)	$ (59,543)	$ (346,419)
Natural gas contracts	48,131	(8,703)	(189,410)
NGL contracts	—	—	(40,973)
Total derivative cash settlement gain (loss), net	6,435	(68,246)	(576,802)
Change in fair value gain	31,055	77,553	241,642
Total derivative gain (loss), net	$ 37,490	$ 9,307	$ (335,160)

As of December 31, 2024, we had entered into the following commodity price derivative contracts:

	Contract Period				
	Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026
Crude Oil Derivatives (volumes in Bbl/day and prices in $/Bbl)					
Swaps					
NYMEX WTI Volumes	31,000	29,000	28,000	11,000	740
Weighted-Average Contract Price	$ 71.08	$ 70.71	$ 72.90	$ 68.54	$ 66.50
Collars					
NYMEX WTI Volumes	28,000	32,000	28,000	45,000	—
Weighted-Average Ceiling Price	$ 79.87	$ 77.78	$ 77.65	$ 75.81	$ —
Weighted-Average Floor Price	$ 70.00	$ 69.88	$ 69.31	$ 58.71	$ —
Natural Gas Derivatives (volumes in MMBtu/day and prices in $/MMBtu)					
Swaps					
NYMEX HH Volumes	180,000	110,000	110,000	110,000	—
Weighted-Average Contract Price	$ 3.17	$ 3.20	$ 3.20	$ 3.20	$ —
Collars					
NYMEX HH Volumes	20,000	20,000	20,000	20,000	130,000
Weighted-Average Ceiling Price	$ 3.76	$ 3.76	$ 3.76	$ 3.76	$ 4.02
Weighted-Average Floor Price	$ 3.03	$ 3.03	$ 3.03	$ 3.03	$ 3.24
Basis Protection Swaps					
Waha Basis Volumes	200,000	130,000	130,000	130,000	130,000
Weighted-Average Contract Price	$ (1.10)	$ (1.17)	$ (1.17)	$ (1.17)	$ (1.31)
Waha Index Volumes	90,000	—	—	—	—
Weighted-Average Contract Price	$ 0.07	$ —	$ —	$ —	$ —

Subsequent to December 31, 2024 and as of February 21, 2025, we had entered into the following commodity price derivative contracts:

	Contract Period				
	Q1 2025	Q2 2025	Q3 2025	Q4 2025	2026
Crude Oil Derivatives (volumes in Bbl/day and prices in $/Bbl)					
Swaps					
NYMEX WTI Volumes	—	—	5,000	2,000	7,397
Weighted-Average Contract Price	$ —	$ —	$ 69.76	$ 69.60	$ 68.46
Collars					
NYMEX WTI Volumes	—	—	—	—	2,466
Weighted-Average Ceiling Price	$ —	$ —	$ —	$ —	$ 77.13
Weighted-Average Floor Price	$ —	$ —	$ —	$ —	$ 60.00

Derivative Assets and Liabilities Fair Value

Our commodity price derivatives are measured at fair value and are included in the accompanying consolidated balance sheets as derivative assets and liabilities. The following table contains a summary of all our derivative positions reported on the accompanying consolidated 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, 2024 and 2023 (in thousands):

	As of December 31,	
	2024	2023
Derivative Assets:		
Commodity contracts - current	$ 66,517	$ 35,192
Commodity contracts - noncurrent	17,037	8,233
Total derivative assets	83,554	43,425
Amounts not offset in the accompanying consolidated balance sheets	(26,520)	(11,859)
Total derivative assets, net	$ 57,034	$ 31,566
Derivative Liabilities:		
Commodity contracts - current	$ (22,178)	$ (18,096)
Commodity contracts - long-term	(13,016)	—
Total derivative liabilities	(35,194)	(18,096)
Amounts not offset in the accompanying consolidated balance sheets	26,520	11,859
Total derivative liabilities, net	$ (8,674)	$ (6,237)

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

We recognize an estimated liability for future costs associated with the abandonment of our crude oil and natural 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 our accompanying consolidated statements of cash flows.

Our estimated asset retirement obligation liability is based on historical experience plugging and abandoning wells, estimated plugging and abandonment cost, estimated economic lives, 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,	
	2024	2023
Balance, beginning of year	$ 336,832	$ 291,026
Additional liabilities incurred with development activities and other	8,556	7,516
Additional liabilities incurred with acquisitions	37,251	40,373
Liabilities settled	(46,526)	(19,136)
Accretion expense	23,327	17,053
Revisions to estimate(1)	126,174	—
Obligations discharged with divestitures	(27,976)	—
Balance, end of year	$ 457,638	$ 336,832
Current portion(2)	58,636	31,116
Long-term portion	399,002	$ 305,716

(1) Revisions to estimates for the year ended December 31, 2024 were primarily a result of (a) increases in our estimated plugging and abandonment cost driven by increased regulatory burden, service costs, complexity of plugging activities, and reclamation and environmental obligations that arose from normal operation of the assets, as evidenced through our plugging program activities during 2024, particularly in the DJ Basin, and (b) the acceleration of the estimated settlement date for certain wells.

(2) The current portion of the asset retirement obligation is included in other liabilities on the accompanying consolidated balance sheets.

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 the Company's 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 warrants, which represent the right to purchase our common stock at a specified exercise price. The number of potentially dilutive shares related to the 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 warrants' term. Warrants are only dilutive when the average price of the common stock during the period exceeds the exercise price. The exercise price of our warrants was in excess of our stock price during the years ended December 31, 2024, 2023, and 2022; therefore, they were excluded from the earnings per share calculation.

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,		
	2024	2023	2022
Net income	$ 838,723	$ 784,288	$ 1,248,080
Basic earnings per common share	$ 8.48	$ 9.09	$ 14.68
Diluted earnings per common share	$ 8.46	$ 9.02	$ 14.58
Weighted-average shares outstanding - basic	98,865	86,240	85,005
Add: dilutive effect of stock awards	311	748	599
Weighted-average shares outstanding - diluted	99,176	86,988	85,604

There were 253,489, 10,948, and 20,699 unvested awards that were anti-dilutive for the years ended December 31, 2024, 2023, and 2022, respectively.

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 consolidated 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,		
	2024	2023	2022
Current tax expense (benefit)			
Federal	$ 4,669	$ (25,537)	$ 51,246
State	3,530	(4,460)	16,950
Total current tax expense (benefit)	8,199	(29,997)	68,196
Deferred tax expense			
Federal	223,636	238,426	289,578
State	12,137	6,737	47,924
Total deferred tax expense	235,773	245,163	337,502
Total income tax expense	$ 243,972	$ 215,166	$ 405,698

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,	
	2024	2023
Deferred tax liabilities:		
Oil and gas properties	$ 1,484,161	$ 1,200,521
Right-of-use assets	25,553	22,654
Commodity derivative contracts	6,429	—
Total deferred tax liabilities	1,516,143	1,223,175
Deferred tax assets:		
Federal and state tax net operating loss carryforward	468,813	504,922
Interest expense carryforward	97,234	33,564
Asset retirement obligations	107,380	79,718
Commodity derivative contracts	—	7,251
Inventory	211	213
Stock-based compensation	10,079	7,327
Lease liability	25,803	22,866
Transaction costs	6,450	6,078
Other long-term assets	25,023	21,859
Total deferred tax assets	740,993	683,798
Less: Valuation allowance	25,404	25,404
Total deferred tax assets after valuation allowance	715,589	658,394
Deferred income tax liabilities, net	$ (800,554)	$ (564,781)

We had $1.9 billion and $2.1 billion of net operating loss carryovers for federal income tax purposes as of December 31, 2024 and 2023, 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 $369.2 million will begin to expire in 2037. Federal net operating loss carryforwards incurred after December 31, 2017 of $1.6 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 a 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, 2024 and 2023, 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,		
	2024	2023	2022
Federal statutory tax expense	$ 227,366	$ 210,458	$ 347,293
Increase (decrease) in tax resulting from:			
State tax expense, net of federal benefit	28,894	26,081	58,658
State tax rate change	(13,202)	(23,002)	—
Return to provision	(1,314)	(1,866)	19,975
Compensation of covered individuals	4,851	5,689	6,138
Stock-based compensation	(1,309)	(2,996)	(3,343)
Bargain purchase gain	—	—	(2,852)
Tax credits	(1,784)	—	(1,405)
Change in valuation allowance	—	—	(19,302)
Other	470	802	536
Total income tax expense	$ 243,972	$ 215,166	$ 405,698

The Vencer 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, 2024, 2023, and 2022. As of December 31, 2024, the Company is subject to U.S. federal and state income tax examination for the years ended December 31, 2023, 2022, and 2021. Tax returns for years prior to 2021 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 was signed into law. Among other provisions, the Inflation Reduction Act imposes a 15% corporate alternative minimum tax (“CAMT”) 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. Based on the application of currently available guidance, the Company’s income tax expense for the year ended December 31, 2024 was not impacted by the CAMT.

NOTE 13 - LEASES

Our right-of-use assets and lease liabilities are recognized on the accompanying consolidated balance sheets within other noncurrent assets, other liabilities, and other long-term liabilities 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,	
	2024	2023
Operating Leases		
Field equipment[1]	$ 68,897	$ 61,662
Corporate leases	12,513	8,864
Vehicles	12,214	7,740
Total right-of-use asset	$ 93,624	$ 78,266
Field equipment[1]	$ 68,978	$ 61,741
Corporate leases	13,682	9,653
Vehicles	12,214	7,740
Total lease liability	$ 94,874	$ 79,134

(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,		
	2024	2023	2022
Operating lease cost	$ 58,680	$ 32,769	$ 21,050
Short-term lease cost[1]	140,780	79,405	55,059
Total lease cost[2]	$ 199,460	$ 112,174	$ 76,109

(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, 2024, 2023, and 2022.

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 consolidated 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, 2024 are as follows:

	Operating Leases
Weighted-average lease term (years)	2.5
Weighted-average discount rate	6.2%

Future commitments by year for our leases with a lease term of greater than one year as of December 31, 2024 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 consolidated balance sheets as follows (in thousands):

	Operating Leases
2025	$ 50,626
2026	26,226
2027	13,248
2028	5,313
2029	3,246
Thereafter	3,815
Total lease payments	102,474
Less: Imputed interest	(7,600)
Total lease liability	$ 94,874

NOTE 14 - SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2024	2023	2022
Supplemental cash flow information:			
Cash (paid) refunded for income taxes	$ 2,858	$ 50,049	$ (97,800)
Cash paid for interest	(408,409)	(37,112)	(28,528)
Supplemental non-cash investing and financing activities:			
Changes in working capital related to capital expenditures	(8,208)	(12,349)	(7,679)
Supplemental cash flow information related to leases:			
Cash paid for amounts included in the measurement of lease liabilities - operating cash flows from operating leases	58,277	32,563	19,541
Right-of-use assets obtained in exchange for new operating lease obligations	69,185	85,521	4,874

NOTE 15 - STOCKHOLDERS' EQUITY

Stock Repurchases

In July 2024, our Board authorized a new stock repurchase program authorizing repurchases of up to $500 million of our outstanding shares of common stock, in the open market, in privately negotiated transactions, or through block trades, derivative transactions, or purchases made in accordance with Rule 10b-18 and Rule 10b5-1 of the Exchange Act. The new stock repurchase program replaced our prior stock repurchase program, which was terminated in connection with the adoption of the new stock repurchase program. The stock repurchase program does not have a termination date, does not require any specific number of shares to be acquired, and can be modified or discontinued by our Board at any time.

We record stock repurchases at cost, which includes transaction costs that are direct and incremental to the repurchase, as a reduction to stockholders' equity. As part of the transaction costs that are direct and incremental to the repurchase 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 consolidated 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.

The table below summarizes stock repurchases pursuant to the stock repurchase program during the year ended December 31, 2024 and 2023:

	Number of Shares (in thousands)	Weighted-Average Price	Total Purchase Price (in thousands)[1]
2024			
Privately negotiated transactions			
NGP Tap Rock Holdings, LLC and certain of its affiliates	876.2	$ 64.54	$ 56,549
Vencer	1,041.7	71.99	75,000
Other transactions	5,394.2	54.81	295,647
Total stock repurchases	7,312.1	$ 58.42	$ 427,196
2023			
Privately negotiated transactions			
CPPIB Crestone Peak Resources Canada Inc.	4,918.0	$ 61.00	$ 300,000
Other transactions	312.8	64.55	20,190
Total stock repurchases	5,230.8	$ 61.21	$ 320,190

(1) Excludes commissions paid and excise taxes accrued related to stock repurchases.

These stock repurchases were funded from our cash on hand, and the shares were immediately retired. As of December 31, 2024, $264.7 million remained available under the program for repurchase of our outstanding common stock. No shares of stock were repurchased in 2022.

Dividends

As approved by our Board, cash dividends are comprised of a quarterly base and a discretionary variable dividend component. The following table summarizes the dividends declared for the years ended December 31, 2024, 2023, and 2022 (in thousands, except per share amounts):

	Year Ended December 31,		
	2024	2023	2022
Base dividend	$ 2.00	$ 2.00	$ 1.89
Variable dividend	2.97	5.60	4.40
Total dividend	$ 4.97	$ 7.60	$ 6.29
Total dividend (in thousands)	$ 489,160	$ 668,669	$ 541,254

All RSUs, DSUs, and PSUs receive a dividend equivalent per unit, recognized as a liability included in other liabilities and other long-term liabilities on the accompanying consolidated balance sheets until the recipients receive the dividend equivalents. Refer to *Note 7 - Stock-Based Compensation* for further discussion around our LTIP.

Capital Return Program

Beginning in February 2025, our Board has elected to prioritize directing the majority of our free cash flow to debt reduction, following the payment of our base dividend, which remains $0.50 per share quarterly. Any incremental returns of capital beyond the base dividend and debt reduction will occur at the discretion of our Board and will be in the form of share repurchases and/or variable dividends. Future dividend payments must be approved by our Board and will depend on our liquidity, financial requirements, and other factors considered relevant by our Board.

NOTE 16 - SEGMENT REPORTING

We report our operations in one reportable upstream segment, which is engaged in the acquisition, development, and production of crude oil and associated liquids-rich natural gas in the DJ Basin in Colorado and the Permian Basin in Texas and New Mexico. The DJ Basin and the Permian Basin are operating segments of the Company that we aggregate into the upstream segment due to the similar nature of these operations that are solely focused in the U.S. The upstream segment derives revenue from the sale of produced crude oil, natural gas, and NGL. We consider our midstream functions as ancillary to our upstream segment. Our chief operating decision maker ("CODM") is our Chief Executive Officer.

The accounting policies of the upstream segment are the same as those described in *Note 1 - Summary of Significant Accounting Policies*. The measure of profit or loss that the CODM uses to assess performance and allocate resources for the upstream segment is Adjusted EBITDAX. Adjusted EBITDAX is defined as earnings before interest, income taxes, depreciation, depletion, and amortization, exploration expense, and other non-cash and non-recurring charges. The measure of segment assets is reported on the accompanying consolidated balance sheets as total consolidated assets. The CODM uses Adjusted EBITDAX to evaluate income generated from segment assets in deciding whether to reinvest profits into the upstream segment or into other activities, such as for acquisitions or to return capital to stockholders through a combination of dividends and/or share repurchases.

Adjusted EBITDAX for the years ended December 31, 2024, 2023, and 2022 was $3.7 billion, $2.4 billion, and $2.3 billion, respectively. As we disclose a single reportable segment, total operating net revenues for the upstream segment are reported in our consolidated statements of operations, segment assets are reported in our consolidated balance sheets, and capital expenditures are reported in our consolidated statements of cash flows.

The CODM is regularly provided with only the consolidated expenses as noted on the face of the consolidated statements of operations. Significant segment expenses included in Adjusted EBITDAX are lease operating expense, midstream operating expense, gathering, transportation, and processing, severance and ad valorem taxes, general and administrative expenses, and derivative cash settlement gain (loss).

The following table presents a reconciliation of reportable segment Adjusted EBITDAX to income from operations before income taxes (in thousands):

	Year Ended December 31,		
	2024	**2023**	**2022**
Adjusted EBITDAX	$ 3,651,621	$ 2,369,190	$ 2,347,585
Exploration	(14,322)	(2,178)	(6,981)
Depreciation, depletion, and amortization	(2,056,427)	(1,171,192)	(816,446)
Abandonment and impairment of unproved properties	—	—	(17,975)
Unused commitments(1)	(1,730)	(5,013)	(3,641)
Transaction costs	(31,419)	(84,328)	(24,683)
Stock-based compensation(2)	(48,272)	(34,931)	(31,367)
Non-recurring general and administrative expense	—	—	(18,037)
Derivative gain (loss), net	37,490	9,307	(335,160)
Derivative cash settlement (gain) loss, net	(6,435)	68,246	576,802
Interest expense	(456,303)	(182,740)	(32,199)
Interest income(3)	11,058	33,347	—
Gain (loss) on property transactions, net	(2,566)	(254)	15,880
Income from operations before income taxes	$ 1,082,695	$ 999,454	$ 1,653,778

(1) Included as a portion of other operating expense in the accompanying consolidated statements of operations.

(2) Included as a portion of general and administrative expense in the accompanying consolidated statements of operations.

(3) Included as a portion of other income in the accompanying consolidated statements of operations.

NOTE 17 - 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,		
	2024	2023	2022
Acquisition[1]	$ 2,155,306	$ 5,039,610	$ 437,100
Development[2]	2,065,070	1,386,371	1,044,392
Exploration	14,322	2,178	6,981
Total	$ 4,234,698	$ 6,428,159	$ 1,488,473

(1) Acquisition costs for proved properties for the years ended December 31, 2024, 2023, and 2022 were $1.9 billion, $4.6 billion, and $420.3 million, respectively. Acquisition costs for unproved properties for the years ended December 31, 2024, 2023, and 2022 were $256.9 million, $414.7 million, and $16.8 million, respectively.

(2) Includes amounts relating to asset retirement obligations of $134.7 million, $7.5 million, and $64.7 million for the years ended December 31, 2024, 2023, and 2022, respectively.

Suspended Well Costs

We did not incur any exploratory well costs during the years ended December 31, 2024, 2023, and 2022.

Reserves

The proved reserve estimates as of December 31, 2024 were audited by Ryder Scott. The proved reserves estimates as of December 31, 2023 and 2022 were prepared by Ryder Scott. 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, 2024, 2023, and 2022 are as follows:

	Crude Oil	Natural Gas	NGL	Total
	(MBbl)	(MMcf)	(MBbl)	(MBoe)
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)
Divestitures 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
Extensions, discoveries, and other additions	51,253	155,483	24,650	101,817
Production	(58,025)	(218,905)	(31,626)	(126,135)
Divestiture of reserves[1]	(9,695)	(41,774)	(6,271)	(22,929)
Removed from capital program	(9,887)	(40,657)	(7,401)	(24,064)
Acquisition of reserves	55,978	354,438	64,297	179,348
Revisions to previous estimates	2,932	10,631	(12,816)	(8,112)
Proved reserves-December 31, 2024[1]	305,361	1,539,518	235,776	797,724
Proved developed reserves:				
December 31, 2022	117,768	750,793	102,004	344,904
December 31, 2023	199,585	1,077,221	162,117	541,239
December 31, 2024	235,626	1,323,856	203,182	659,451
Proved undeveloped reserves:				
December 31, 2022	34,834	116,707	16,830	71,115
December 31, 2023	73,220	243,081	42,826	156,560
December 31, 2024	69,735	215,662	32,594	138,273

(1) Items may not recalculate due to rounding.

During the years ended December 31, 2024, 2023, and 2022, horizontal development resulted in extensions, discoveries, and other additions of 101.8 MMBoe, 21.5 MMBoe, and 27.9 MMBoe, respectively.

During the years ended December 31, 2024, 2023, and 2022, proved undeveloped reserves were reduced by 24.1 MMBoe, 4.8 MMBoe, and 0.2 MMBoe respectively, primarily due to the removal of proved undeveloped locations from our five-year drilling program.

As of December 31, 2024, we revised our proved reserves downward by 8.1 MMBoe. The 8.1 MMBoe negative revision of proved reserves as compared to previous estimates was the result of: (i) negative revisions of 23.0 MMBoe driven by 2024 negative Waha pricing differentials, natural gas shrinks, and NGL yields, (ii) negative revisions of 12.8 MMBoe from non-producing wells that have been or are planned to be plugged and abandoned and other, and (iii) negative price-related revisions of 9.6 MMBoe that resulted from the decrease to SEC prices of $2.74 to $75.48 per Bbl WTI for crude oil and $0.51 to $2.13 per MMBtu HH for natural gas. Negative revisions were partially offset by 27.6 MMBoe from updates to well performance and 9.7 MMBoe for increases in interest and other.

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) negative revisions of 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.

The standardized measure of discounted future net cash flows relating to proved 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,		
	2024	**2023**	**2022**
Future cash flows	$ 28,250,810	$ 27,947,743	$ 23,225,188
Future production costs	(12,006,734)	(11,038,268)	(6,490,522)
Future development costs	(2,491,009)	(2,366,582)	(1,337,494)
Future income tax expense	(1,243,949)	(1,605,756)	(2,870,178)
Future net cash flows	12,509,118	12,937,137	12,526,994
10% annual discount for estimated timing of cash flows	(4,193,705)	(4,667,858)	(4,599,504)
Standardized measure of discounted future net cash flows	$ 8,315,413	$ 8,269,279	$ 7,927,490

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,		
	2024	2023	2022
Beginning of period	$ 8,269,279	$ 7,927,490	$ 4,412,104
Crude oil, natural gas, and NGL sales, net of production costs	(3,807,145)	(2,558,095)	(2,980,527)
Net changes in prices and production costs	(1,638,518)	(4,385,615)	5,016,678
Net changes in extensions, discoveries, and other additions	1,415,760	363,594	638,537
Development costs incurred	810,591	447,181	411,138
Changes in estimated development cost	39,668	(39,386)	(87,466)
Acquisition of reserves	2,342,362	5,199,814	627,833
Divestiture of reserves	(257,413)	(32,483)	—
Revisions of previous quantity estimates	(225,151)	(529,185)	619,800
Net change in income taxes	210,815	796,068	(991,734)
Accretion of discount	1,172,236	983,428	532,716
Changes in production rates and other	(17,071)	96,468	(271,589)
End of period	$ 8,315,413	$ 8,269,279	$ 7,927,490

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, 2024, 2023, and 2022, as required by the SEC.

	Year Ended December 31,		
	2024	2023	2022
Crude Oil (per Bbl)	$ 74.12	$ 75.57	$ 90.28
Natural Gas (per Mcf)	$ 0.62	$ 2.03	$ 5.54
NGL (per Bbl)	$ 19.80	$ 22.69	$ 39.05

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, 2024. 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, 2024, 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, 2024, 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, 2024. Management included in its assessment of internal control over financial reporting all consolidated entities.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2024, 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, 2024 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, 2024, 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, 2024, 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, 2024, of the Company and our report dated February 24, 2025, expressed an unqualified opinion on those financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte & Touche LLP

Denver, Colorado
February 24, 2025

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

During the three months ended December 31, 2024, no director or officer of the Company adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

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, 2024.

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, 2024.

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, 2024.

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, 2024.

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, 2024.

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	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).
2.2	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).
2.3	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).
2.4	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).
2.5	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 (incorporated by reference to Exhibit 2.10 to Civitas Resources, Inc.'s Annual Report on Form 10-K filed on February 27, 2024).
2.6	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 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).
10.2*	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).
10.3*	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).
10.4*	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).
10.5*	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).
10.6*	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).
10.7*	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).
10.8*	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).
10.9*	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).
10.10*	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).
10.11*	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).

10.12*	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).
10.13*	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).
10.14*	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)
10.15	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).
10.16	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).
10.17	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).
10.18	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).
10.19	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).
10.20	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).
10.21	Sixth Amendment to Amended and Restated Credit Agreement, dated June 12, 2024, 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 14, 2024).
10.22†	Seventh Amendment to Amended and Restated Credit Agreement, dated February 21, 2025, among Civitas Resources, Inc., the guarantors party thereto, the lenders party thereto, and JPMorgan Chase Bank, N.A., as the administrative agent.
10.23	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).
10.24*	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).
10.25*	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).
10.26*	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).
10.27*	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).

10.28*	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).
10.29*†	Employment Letter, dated as of November 28, 2023, by and between Civitas Resources, Inc. and Kayla D. Baird
10.30*†	Employment Letter, dated as of August 3, 2023, by and between Civitas Resources, Inc. and Jeffrey S. Kelly.
10.31*	Form of Employee Restrictive Covenants, Proprietary Information and Inventions Agreement (incorporated by reference to Exhibit 10.49 to Civitas Resources, Inc.'s Annual Report on Form 10-K filed on February 27, 2024).
10.32*	Civitas Resources, Inc. Amended & Restated Independent Director Compensation Program (incorporated by reference to Exhibit 10.46 to Civitas Resources, Inc's Annual Report on Form 10-K filed on February 27, 2024).
10.33*	Form of Director Restricted Stock Unit Agreement under the Civitas Resources, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.47 to Civitas Resources, Inc.'s Annual Report on Form 10-K filed on February 27, 2024).
10.34*	Form of Director Restricted Stock Unit Agreement under the Extraction Oil & Gas, Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.48 to Civitas Resources, Inc.'s Annual Report on Form 10-K filed on February 27, 2024).
10.35*	Civitas Resources, Inc. 2024 Long Term Incentive Plan (incorporated by reference to Exhibit 4.1 to Civitas Resources, Inc.'s Registration Statement on Form S-8 filed on June 10, 2024).
10.36*†	Form of Officer Restricted Stock Unit Agreement under the Civitas Resources, Inc. 2024 Long Term Incentive Plan.
10.37*†	Form of Officer Performance Stock Unit Agreement under the Civitas Resources, Inc. 2024 Long Term Incentive Plan.
10.38*	Form of Director Restricted Stock Unit Award Agreement under the Civitas Resources, Inc. 2024 Long Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Civitas Resources, Inc.'s Quarterly Report on Form 10-Q filed on August 1, 2024).
10.39*†	Form of Cash Award Agreement under the Civitas Resources, Inc. 2024 Long Term Incentive Plan.
19†	Civitas Resources, Inc. Amended and Restated Corporate Policy on Insider Trading.
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 (incorporated by reference to Exhibit 97 to Civitas Resources, Inc's Annual Report on Form 10-K filed on February 27, 2024)
99.1†	Report of Independent Petroleum Engineers, Ryder Scott Company, L.P., for reserves as of December 31, 2024
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 24, 2025	By:	/s/ M. Christopher Doyle
		M. Christopher 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 M. Christopher 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 24, 2025

By: /s/ M. Christopher Doyle
M. Christopher 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 M. Trimble
Director

By: /s/ Howard A. Willard, III
Howard A. Willard, III
Director

By: /s/ Jeffrey E. Wojahn
Jeffrey E. Wojahn
Director