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

FORM 10-K

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

For the fiscal year ended December 31, 2023

or

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

Commission File No. 001-36120

ANTERO RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**80-0162034**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1615 Wynkoop Street, Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

(303) 357-7310
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.01	AR	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. ☐

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

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. ☒

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2023, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $5.4 billion based on the $23.03 per share closing price of Antero Resources Corporation's common stock as reported on that day on the New York Stock Exchange.

Number of shares of the registrant's common stock outstanding as of February 9, 2024 (in thousands): 303,568

Documents incorporated by reference: Portions of the registrant's proxy statement for its annual meeting of stockholders to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end are incorporated by reference into Part III of this Annual Report on Form 10-K.

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GLOSSARY OF COMMONLY USED TERMS

The following are abbreviations and definitions of certain terms used in this document, some of which are commonly used in the oil and gas industry:

"2026 Convertible Notes." The 4.25% convertible senior notes due September 1, 2026.

"Antero Midstream." Antero Midstream Corporation

"*ASC.*" Accounting Standards Codification.

"*ASU.*" Accounting Standards Update.

"*Basin.*" A large natural depression on the earth's surface in which sediments, generally brought by water, accumulate.

"*Bbl.*" One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, NGLs or water.

"*Bbl/d.*" Bbl per day.

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

"Bcf/d." Bcf per day.

"*Bcfe.*" One billion cubic feet of natural gas equivalent with one barrel of oil, condensate, or NGLs converted to six thousand cubic feet of natural gas.

"*Btu.*" British thermal unit.

"*C3+ NGLs.*" Natural gas liquids excluding ethane, consisting primarily of propane, isobutane, normal butane and natural gasoline.

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

"CPI." Consumer Price Index.

"*Credit Facility.*" Collectively, the senior secured revolving credit facility in effect for periods before October 26, 2021 and the senior secured revolving credit facility in effect on and after October 26, 2021.

"*DD&A.*" Depletion, depreciation and amortization.

"*Delineation.*" The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

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

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

"*Dry hole.*" A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*EPA.*" United States Environmental Protection Agency.

"*ESG.*" Environmental, social and governance.

"*Exploratory well.*" A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir, or to extend a known reservoir.

"*FASB.*" Financial Accounting Standards Board.

"*FERC*." Federal Energy Regulatory Commission.

"*Field*." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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

"*Fresh water*." Water that is either (i) raw fresh water or (ii) produced or flowback water that has been treated, including through blending operations.

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

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

"*GHG*." Greenhouse gas.

"*Horizontal drilling*." A drilling technique where a well is drilled vertically to a certain depth and then drilled along a horizontal path oriented at approximately 85 to 95 degrees from a vertical direction within a specified interval.

"Hydrocarbon." An organic compound containing only carbon and hydrogen

"IRS." The Internal Revenue Service of the United States of America

"*Joint Venture*." The joint venture entered into on February 6, 2017 between Antero Midstream Partners LP, a wholly owned subsidiary of Antero Midstream and MarkWest, a wholly owned subsidiary of MPLX, LP, to develop processing and fractionation assets in Appalachia.

"*Liquids-rich*." Natural gas with a heating value of at least 1,100 Btu per Mcf.

"*LPG*." Liquefied petroleum gas consisting of propane and butane.

"*MarkWest*." MarkWest Energy Partners, L.P.

"Martica." Martica Holdings LLC.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*Mcf*." One thousand cubic feet of natural gas.

"*Mcfe*." One thousand cubic feet of natural gas equivalent, with liquids converted to an equivalent volume of natural gas using the ratio of one barrel of oil to six Mcf of natural gas.

"*MMBbl*." One million barrels of crude oil, condensate or NGLs.

"*MMBtu*." One million British thermal units.

"*MMBtu/d*." MMBtu per day.

"*MMcf*." One million cubic feet of natural gas.

"*MMcf/d*." MMcf per day.

"*MMcfe*." One million cubic feet of natural gas equivalent with one barrel of oil, condensate or NGLs converted to six thousand cubic feet of natural gas.

"*MMcfe/d*." MMcfe per day.

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

“*Net well*.” The percentage ownership interest in a well that an owner has based on the working interest. An owner who has a 50% working interest in a well has a 0.50 net well.

“*NGLs*.” Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as purity products such as ethane, propane, isobutane, normal butane and natural gasoline.

“*NYMEX*.” The New York Mercantile Exchange.

“*Potential well locations*.” Total gross locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas, NGLs and oil prices, costs, drilling results and other factors.

“*Productive well*.” A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

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

“*Proved developed reserves*.” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“*Proved reserves*.” The estimated quantities of natural gas, NGLs and oil that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

“*Proved undeveloped reserves*” *or “PUD.*” Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

“*PV-10*.” When used with respect to oil and gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using average yearly prices computed using SEC rules, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV-10 is not a financial measure calculated in accordance with GAAP and generally differs from Standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized measure represents an estimate of the fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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

“SEC.” The United States Securities and Exchange Commission.

“Senior Notes.” Collectively, the 5.00% senior notes due March 1, 2025, 8.375% senior notes due July 15, 2026, 7.625% senior notes due February 1, 2029 and 5.375% senior notes due March 1, 2030, as applicable.

“*Spacing*.” The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, or distance between two horizontal well legs, and is often established by regulatory agencies.

“*Standardized measure*.” Discounted future net cash flows estimated by applying year end prices to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

“*Strip prices*.” The daily settlement prices of commodity futures contracts, such as those for natural gas, NGLs and oil. Strip prices represent the prices at which a given commodity can be sold at specified future dates, which may not represent actual market prices available upon such date in the future.

"*Swaption.*" An instrument that provides the holder with the right, but not the obligation, to enter into a fixed price swap at a specified future date.

"*Tcf*." One trillion cubic feet of natural gas.

"*Tcfe*." One trillion cubic feet of natural gas equivalent with one barrel of oil, condensate, or NGLs converted to six thousand cubic feet of natural gas.

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

"VIE." Variable Interest Entity.

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

"*WTI*." West Texas Intermediate light sweet crude oil.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Some of the information in this Annual Report on Form 10-K may contain “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this Annual Report on Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward looking statements. Words such as “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-looking statements, although not all forward-looking statements contain such identifying words. When considering these forward-looking statements, investors should keep in mind the risk factors and other cautionary statements in this Annual Report on Form 10-K. These forward-looking statements are based on management’s current beliefs, based on currently available information, as to the outcome and timing of future events. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- our ability to execute our business strategy;
- our production and oil and gas reserves;
- our financial strategy, liquidity and capital required for our development program;
- our ability to obtain debt or equity financing on satisfactory terms to fund acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- our ability to execute our return of capital program;
- natural gas, NGLs and oil prices;
- impacts of geopolitical events, including the conflicts in Ukraine and in the Middle East, and world health events;
- timing and amount of future production of natural gas, NGLs and oil;
- our hedging strategy and results;
- our ability to meet minimum volume commitments and to utilize or monetize our firm transportation commitments;
- our future drilling plans;
- our projected well costs;
- competition;
- government regulations and changes in laws;
- pending legal or environmental matters;
- marketing of natural gas, NGLs and oil;
- leasehold or business acquisitions;
- costs of developing our properties;
- operations of Antero Midstream;
- our ability to achieve our GHG reduction targets and the costs associated therewith;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and

- our other plans, objectives, expectations and intentions contained in this Annual Report on Form 10-K.

We caution investors that these forward-looking statements are subject to all of the risks and uncertainties incidental to our business, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, commodity price volatility, inflation, supply chain or other disruption, availability and cost of drilling, completion and production equipment and services, environmental risks, drilling and completion and other operating risks, marketing and transportation risks, regulatory changes or changes in law, the uncertainty inherent in estimating natural gas, NGLs and oil reserves and in projecting future rates of production, cash flows and access to capital, the timing of development expenditures, conflicts of interest among our stockholders, impacts of geopolitical and world health events, cybersecurity risks, the state of markets for, and availability of, verified quality carbon offsets and the other risks described under the heading "Item 1A. Risk Factors" in this Annual Report on Form 10-K.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data, and the price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities, or changes in commodity prices, may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report on Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report on Form 10-K are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements to reflect events or circumstances after the date of this Annual Report on Form 10-K.

SUMMARY RISK FACTORS

Commodity Prices

- Natural gas, NGLs and oil price volatility, or a substantial or prolonged period of low natural gas, NGLs and oil prices, may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations 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, we will be required to take write-downs of the carrying values of our properties.

Reserves

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

- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

- Unless we replace our reserves with new reserves and develop those reserves, our reserves and, eventually, production will decline, which would adversely affect our future cash flows and results of operations.

- Approximately 50% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flows and income.

Business Operations

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

- Properties that we decide to drill may not yield natural gas, NGLs or oil in commercially viable quantities, which may adversely affect our financial condition, results of operations and cash flows.

- Market conditions or operational impediments, such as the unavailability of satisfactory transportation arrangements, may hinder our access to natural gas, NGLs and oil markets or delay our production.

- Our ability to produce natural gas, NGLs and oil economically and in commercial quantities is dependent on the availability of adequate supplies of water for drilling and completion operations and access to water and waste disposal or recycling facilities and services at a reasonable cost. Restrictions on our ability to obtain water or dispose of produced water and other waste may have an adverse effect on our financial condition, results of operations and cash flows.

- Our failure to develop, obtain, access or maintain the necessary infrastructure to successfully deliver natural gas, NGLs and oil to market may adversely affect our business, financial condition or results of operations.

- Increasing attention to ESG matters and conservation measures may adversely impact our business.

Customer Concentration and Credit Risk

- The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

- Hedging transactions may become more costly or unavailable to us and expose us to counterparty credit risk.

Vendor Risks

- We are required to pay fees to our service providers based on minimum volumes under long-term contracts regardless of actual volume throughput.

- Interruptions in operations at facilities that process and fractionate our gas may adversely affect our business, financial condition and results of operations.

Acquisitions, Divestitures and Takeovers

- Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Capital Structure and Access to Capital

- Our exploration and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our oil and gas reserves.

- We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

- The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility.

- Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Compliance with Regulations

- Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

- Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

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

- Our operations are subject to a series of risks related to climate change that could result in increased operating costs, limit the areas in which we may conduct oil and natural gas exploration and production activities, and reduce demand for our products.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

Our Company and Organizational Structure

Antero Resources Corporation (individually referred to as "Antero") and its consolidated subsidiaries (collectively referred to as "Antero Resources," the "Company," "we," "us" or "our") are engaged in the development, production, exploration and acquisition of natural gas, NGLs and oil properties located in the Appalachian Basin. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs and oil from unconventional formations. As of December 31, 2023, we held approximately 515,000 net acres of natural gas, NGLs and oil properties located in the Appalachian Basin primarily in West Virginia and Ohio. Our corporate headquarters is in Denver, Colorado.

Ownership in Antero Midstream

Antero Midstream is a growth-oriented midstream energy company formed to own, operate and develop midstream energy assets that primarily service our completion and production activity in the Appalachian Basin. Antero Midstream's assets consist of gathering systems and compression facilities, water handling and blending facilities, and interests in processing and fractionation plants, through which it provides services to us under long-term contracts.

We have an interest in Antero Midstream that provides significant influence, but not control, over Antero Midstream. As a result, we account for our interest in Antero Midstream using the equity method of accounting. As of December 31, 2023, we owned 29.0% of Antero Midstream's common stock.

General

The following table provides a summary of selected data for our Appalachian Basin natural gas, NGLs and oil assets as of the date and for the period indicated.

	As of December 31, 2023					Three Months Ended December 31, 2023
	Proved Reserves [1] [2] (Bcfe)	PV-10 [3] (in millions)	Net Proved Developed Wells [4]	Total Net Acres	Gross Potential Drilling Locations [5]	Average Net Daily Production (MMcfe/d)
Appalachian Basin	18,121	$ 5,929	1,447	515,217	1,588	3,420
Discounted future income taxes		(834)				
Standardized Measure [6]		$ 5,095				

(1) Estimated proved reserve volumes and values were calculated assuming partial ethane recovery, with rejection of the remaining ethane and using the unweighted twelve-month average of the first-day-of-the-month prices for the period ended December 31, 2023, which were $2.63 per Mcf for natural gas based on a $2.64 per MMBtu NYMEX reference price, $11.75 per Bbl for ethane, $38.01 per Bbl for C3+ NGLs and $64.97 per Bbl for oil for the Appalachian Basin based on a $78.21 per Bbl WTI reference price.

(2) Proved reserves for the noncontrolling interests in Martica as of December 31, 2023 were 75 Bcfe.

(3) PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted amount of estimated future income taxes. Future income taxes are not basin specific, and therefore, the standardized measure is only at a company level. See Note 19—Supplemental Information on Oil and Gas Producing Activities to the consolidated financial statements for more information about the calculation of standardized measure.

(4) Excludes certain vertical wells with no proved reserves booked that were primarily acquired in conjunction with leasehold acreage acquisitions.

(5) Gross potential drilling locations are comprised of 248 locations classified as proved undeveloped and 1,340 locations classified as probable and possible. See "Item 1A. Risk Factors" for risks and uncertainties related to developing our potential well locations contained in our proved, probable and possible reserve categories.

(6) Standardized measure of discounted future net cash flows for the noncontrolling interests in Martica as of December 31, 2023 was $170 million.

For the year ended December 31, 2023, our total consolidated capital expenditures were $1.1 billion, including drilling and completion expenditures of $909 million, leasehold additions of $148 million and other capital expenditures of $15 million. We completed 70 net horizontal wells during the year ended December 31, 2023. Our net capital budget for 2024 is $725 million to $800 million. Our budget includes: a range of $650 million to $700 million for drilling and completion and $75 million to $100 million for leasehold expenditures. We do not budget for acquisitions other than leasehold acquisitions. During 2024, we plan to complete 45 to 50 net horizontal wells in the Appalachian Basin. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities and commodity prices.

Business Strategy and Competitive Strengths

Experienced Management Team

Our management team has worked together for many years and has established a successful track record of executing in unconventional resource plays. We intend to leverage our team's experience delineating and developing natural gas resource plays to continue developing our reserves and production, primarily on our existing multi-year project inventory.

Strong Balance Sheet and Sustainable Leverage Profile

We are focused on maintaining a strong balance sheet, which includes maintaining a sustainable leverage profile. As of December 31, 2022 and 2023, we had total debt of $1.2 billion and $1.5 billion, respectively. See Note 7—Long-Term Debt to the consolidated financial statements and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Debt Agreements" for further information on our outstanding debt and debt agreements.

Focused, Long-Lived Asset Base with Sufficient Takeaway Capacity

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Appalachian Basin where we have a substantial inventory of liquids-rich locations. Additionally, we have secured sufficient long-term firm takeaway capacity on major pipelines in our core operating area to accommodate our current development plans and move our production to various markets.

Integrated Business Platform

We operate in the following reportable segments: (i) the exploration, development and production of natural gas, NGLs and oil; (ii) marketing of excess firm transportation capacity; and (iii) midstream services through our equity method investment in Antero Midstream. See Note 17—Reportable Segments to the consolidated financial statements for further discussion on our industry segment operations.

Culture of Continuous Improvement and Responsible Stewardship

We are committed to a culture of continuous improvement, which serves as our foundation to develop and achieve our ESG goals as well as further our goal of environmental stewardship. Innovation, collaboration, technology and establishing meaningful goals have enabled us to improve our safety record, partner with Antero Midstream to recycle or reuse a substantial majority of our flowback and produced water and further our commitment to lowering GHG emission intensity across our operations. We believe natural gas is key to the energy transition because of its ability to provide energy security to developing nations and replace more GHG-intensive sources of fuel. We embrace our role in supporting the goal of a low-carbon future and seek to build upon past GHG emission reduction efforts. Our 2022 ESG Report, available on our website at *www.anteroresources.com/esg*, includes more information on our ESG goals, as well as specific initiatives we have in place to help achieve these goals. Our 2022 ESG Report and other information on our website is not incorporated into this Annual Report on Form 10-K or our other filings with the SEC and is not a part of them. Additionally, see "—Regulation of Environmental and Occupational Safety and Health Matters" for more information on GHG emissions and "Item 1A. Risk Factors" for risks and uncertainties related to our business operations.

Hedge Program

We may utilize a hedging program to mitigate volatility in commodity prices and to protect certain of our expected future cash flows when circumstances warrant. However, due to our improved liquidity and leverage position as compared to historical levels, the percentage of our expected production that we hedge has decreased substantially. Our hedging program may include commodity fixed price swaps, basis swaps, collars or other similar instruments related to the price risk associated with our production. Additionally, our consolidated VIE, Martica, also enters into hedging contracts for natural gas, NGLs and oil, and the gains and losses from such contracts are fully attributable to the noncontrolling interests in Martica. As of December 31, 2023, the estimated fair value of our commodity net derivative contracts was a liability of $37 million. See Note 11—Derivative Instruments to the consolidated financial statements for more information.

Asset Sales

Drilling Partnership

On February 17, 2021, we announced the formation of a drilling partnership with QL Capital Partners ("QL"), an affiliate of Quantum Energy Partners, for our 2021 through 2024 drilling program. Under the terms of the arrangement, each year in which QL participates represents an annual tranche, and QL will be conveyed a working interest in any wells spud by us during such tranche year. For 2021 through 2024, we agreed to the estimated internal rate of return ("IRR") of our capital budget for each annual tranche, and QL agreed to participate in all four annual tranches. We develop and manage the drilling program associated with each tranche, including the selection of wells. Additionally, for each annual tranche, we will enter into assignments, bills of sale and conveyances pursuant to which QL will be conveyed a proportionate working interest percentage in each well spud in that year, which conveyances will not be subject to any reversion.

Under the terms of the arrangement, QL funded development capital of 20%, 15% and 15% for wells spud in 2021, 2022 and 2023, respectively, and will fund 20% of development capital for wells spud in 2024, which funding amounts represent QL's proportionate working interest in such wells. Additionally, we may receive a carry in the form of a one-time payment from QL for each annual tranche if the IRR for such tranche exceeds certain specified returns, which will be determined no earlier than October 31 and no later than December 1 following the end of each tranche year. We received a carry of $29 million for each of the 2021 and 2022 tranches during the years ended December 31, 2022 and 2023. All of the wells spud during each calendar year period will be a separate annual tranche. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche will be for our account. Subject to the preceding sentence, for any wells included in a tranche, QL is obligated and responsible for its working interest share of costs and liabilities, and is entitled to its working interest share of revenues, associated with such wells for the life of such wells. See Note 3—Transactions to the consolidated financial statements for more information.

Our Properties and Operations

Reserves

The table below summarizes our estimated proved reserves as of December 31, 2022 and 2023, which were prepared assuming partial ethane recovery, and rejection of the remaining ethane. When ethane is rejected at the processing plant, it is left in the gas stream and sold with the methane gas.

	Natural Gas (Bcf)	NGLs (MMBbl)	Oil and Condensate (MMBbl)	Equivalents (Bcfe)	Percentage of Proved Reserves
As of December 31, 2022 (1)					
Proved developed reserves (2)	7,699	930	16	13,373	75 %
Proved undeveloped reserves (3)	2,571	287	15	4,386	25 %
Total	10,270	1,217	31	17,759	100 %
As of December 31, 2023 (1)					
Proved developed reserves (2)	7,912	963	15	13,783	76 %
Proved undeveloped reserves (3)	2,702	259	14	4,338	24 %
Total	10,614	1,222	29	18,121	100 %

(1) Unweighted 12 month average prices of the first-day-of-the-month for the period ended December 31, 2022 were $6.22 per Mcf for natural gas, $20.05 per Bbl for ethane, $56.01 per Bbl for C3+ NGLs and $85.33 per Bbl for oil for the Appalachian Basin based on a $94.14 WTI reference price. Unweighted 12 month average prices of the first-day-of-the-month for the period ended December 31, 2023 were $2.63 per Mcf for natural gas, $11.75 per Bbl for ethane, $38.01 per Bbl for C3+ NGLs and $64.97 per Bbl for oil for the Appalachian Basin based on a $78.21 WTI reference price.

(2) Proved developed reserves for the noncontrolling interests in Martica as of December 31, 2022 were 91 Bcfe, which consisted of 70 Bcf of natural gas, 3 MMBbl of NGLs and 0.2 MMBbl of oil and condensate. Proved developed reserves for the noncontrolling interests in Martica as of December 31, 2023 were 75 Bcfe, which consisted of 58 Bcf of natural gas, 3 MMBbl of NGLs and 0.1 MMBbl of oil and condensate.

(3) Proved undeveloped reserves for the noncontrolling interests in Martica as of December 31, 2022 were 1 Bcfe, which consisted entirely of natural gas. There were no proved undeveloped reserves for the noncontrolling interests in Martica as of December 31, 2023.

Proved Reserves

The following table summarizes the changes in our estimated proved reserves (in Bcfe):

Proved reserves, December 31, 2022	**17,759**
Extensions, discoveries and other additions	413
Revisions of previous estimates	814
Revisions to five-year development plan	454
Price revisions	(81)
Production	(1,238)
Proved reserves, December 31, 2023	**18,121**

Extensions and discoveries of 413 Bcfe of proved reserves resulted from delineation and developmental drilling in the Appalachian Basin. Revisions of previous estimates of 814 Bcfe includes an upward revision of 846 Bcfe for increases in our ownership interests, partially offset by downward revisions of 32 Bcfe related to changes in our reserve forecast and operation cost estimates. Revisions to the five-year development plan of 454 Bcfe includes an upward revision of 698 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to the Company's five-year development plan, partially offset by a downward revision of 244 Bcfe for locations that were not developed within five years of initial booking as proved reserves. Price revisions of 81 Bcfe are due to decreases in prices for natural gas, NGLs and oil between periods. Estimated proved reserves as of December 31, 2023 totaled 18.1 Bcfe, an increase of 2.0% from December 31, 2022.

Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated proved undeveloped reserves (in Bcfe):

Proved undeveloped reserves, December 31, 2022	**4,386**
Extensions, discoveries and other additions	413
Revisions of previous estimates	470
Revisions to five-year development plan	501
Reclassifications to proved developed reserves.	(1,432)
Proved undeveloped reserves, December 31, 2023	**4,338**

Extensions and discoveries of 413 Bcfe of proved undeveloped reserves resulted from delineation and developmental drilling in the Appalachian Basin. Revisions of previous estimates of 470 Bcfe includes an upward revision of 605 Bcfe for increases in our ownership interests, partially offset by downward revisions of 135 Bcfe primarily related to ethane recovery. Revisions to the five-year development plan of 501 Bcfe includes an upward revision of 745 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to the Company's five-year development plan, partially offset by a downward revision of 244 Bcfe for locations that were not developed within five years of initial booking as proved reserves.

During the year ended December 31, 2023, we converted 1,432 Bcfe, or 33% of our proved undeveloped reserves to proved developed reserves and incurred drilling and completion costs of $685 million. We spent an additional $271 million on development costs related primarily to drilled and uncompleted wells and properties in the proved undeveloped classification as of December 31, 2023, resulting in total development costs incurred of $956 million, as disclosed in Note 19—Supplemental Information on Oil and Gas Producing Activities to the consolidated financial statements. Estimated future development costs relating to the development of our proved undeveloped reserves as of December 31, 2023 are $1.8 billion, or $0.42 per Mcfe, over the next five years. We maintain a five-year development plan, which is reviewed by our Board of Directors, which supports our maintenance capital program. The development plan is reviewed annually to ensure capital is allocated to the wells that have the highest risk-adjusted rates of return within our inventory of undrilled well locations. Based on strip pricing as of December 31, 2023, we believe that net cash provided by operating activities will be sufficient to finance such future development costs. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also continue drilling our proved undeveloped reserves. See "Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

As of December 31, 2023, an estimated 4,598 of our net leasehold acres, containing 144 gross wells (16 net wells) associated with proved undeveloped reserves, are subject to renewal prior to scheduled drilling. Some of these leases have contract renewal options and some will need to be renegotiated. We estimate a potential cost of $17 million to renew the 4,598 acres based upon current leasing authorizations and option to extend payments. Proved undeveloped reserves of 337 Bcfe are related to these leases.

Historically, we have had a high success rate in renewing leases, and we expect that we will be able to renew substantially all of the leases underlying this acreage prior to the scheduled drilling dates. Based on our historical success rate in renewing leases, we estimate that we may not be able to renew leases covering 17 Bcfe of these proved undeveloped reserves.

If we are not able to renew these leases prior to the scheduled drilling dates, our quantities of net proved undeveloped reserves will be somewhat reduced on those locations.

Preparation of Reserve Estimates

Our proved reserve estimates as of December 31, 2021, 2022 and 2023 included in this Annual Report on Form 10-K were prepared by our internal reserve engineers in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. These proved reserve estimates have been audited by our independent engineers, DeGolyer and MacNaughton ("D&M"). A copy of the summary report of D&M with respect to our reserves as of December 31, 2023 is filed as Exhibit 99.1 to this Annual Report on Form 10-K. The technical person at D&M primarily responsible for reviewing our reserves estimates was Dilhan Ilk, P.E. Mr. Ilk is a Registered Professional Engineer in the State of Texas (License No. 139334), is a member of the Society of Petroleum Engineers, and has in excess of 10 years of experience in oil and gas reservoir studies and reserves evaluations. Mr. Ilk graduated from the Istanbul Technical University in 2003 with a Bachelor of Science degree in Petroleum Engineering, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005 and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers and geoscience professionals works closely with D&M to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserve auditing process. Periodically, our technical team meets with D&M to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Our internally prepared reserve estimates and related reports are reviewed and approved by our Senior Vice President – Reserves, Planning and Midstream, W. Patrick Ash. Mr. Ash has served as Senior Vice President – Reserves, Planning and Midstream since June 2019. Previously, he served as Vice President – Reservoir Engineering and Planning from December 2017 to June 2019. Prior to December 2017, Mr. Ash was at Ultra Petroleum for six years in management positions of increasing responsibility, most recently serving as Vice President, Development. In this position he led the reservoir engineering, geoscience, and corporate engineering groups. From 2001 to 2011, Mr. Ash served in engineering roles at Devon Energy, NFR Energy and Encana Corporation. Mr. Ash holds a B.S. in Petroleum Engineering from Texas A&M University and an MBA from Washington University in St. Louis.

Our senior management and Board of Directors also reviews our reserve estimates and related reports with Mr. Ash and other members of our technical staff. Additionally, our senior management reviews and approves any significant changes to our proved reserves on a quarterly basis.

Identification of Potential Well Locations

Our identified potential well locations represent locations to which proved, probable, or possible reserves were attributable based on SEC pricing as of December 31, 2023.

Production, Price and Cost History

Natural gas, NGLs and oil are commodities, and the prices that we receive for our production are largely a function of market supply and demand. Demand for our products is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas, NGLs or oil can result in substantial price volatility. A substantial or extended decline in commodity prices, or poor drilling results, could have a material adverse effect on our financial position, results of operations, cash flows, quantities of reserves that may be economically produced and our ability to access capital markets. See "Item 1A. Risk Factors— Natural gas, NGLs and oil price volatility, or a substantial or prolonged period of low natural gas, NGLs and oil prices, may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

Exploration and Production and Marketing Segments

The following table sets forth information regarding our production, realized prices and production costs for the years ended December 31, 2021, 2022 and 2023. For additional information on price calculations, see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

		Year Ended December 31,		
		2021	**2022**	**2023**
Production data (1) (2):				
Natural gas (Bcf)		826	798	815
C2 Ethane (MBbl)		17,262	18,818	24,657
C3+ NGLs (MBbl)		40,496	39,914	41,927
Oil (MBbl)		3,521	3,223	3,874
Combined (Bcfe)		1,194	1,170	1,238
Daily combined production (MMcfe/d)		3,271	3,204	3,392
Average prices before effects of derivative settlements (3):				
Natural gas (per Mcf)	$	4.17	6.92	2.69
C2 Ethane (per Bbl) (4)	$	11.99	20.41	10.14
C3+ NGLs (per Bbl)	$	47.92	52.98	37.85
Oil (per Bbl)	$	57.15	85.53	63.80
Combined average sales prices before effects of derivative settlements (per Mcfe) (1)	$	4.85	7.09	3.45
Combined average sales prices after effects of derivative settlements (per Mcfe) (1)	$	3.88	5.46	3.43
Average Costs (per Mcfe):				
Lease operating	$	0.08	0.09	0.10
Gathering, compression, processing and transportation	$	2.09	2.23	2.13
Production and ad valorem taxes	$	0.17	0.25	0.13
Marketing, net	$	0.08	0.10	0.06
General and administrative (excluding equity-based compensation)	$	0.10	0.12	0.13
Depletion, depreciation, amortization and accretion	$	0.62	0.59	0.56

(1) Production data excludes volumes related to the volumetric production payment transaction ("VPP").
(2) Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and may not reflect their relative economic value.
(3) Average prices reflect the before and after effects of our settled commodity derivatives. Our calculation of such after effects includes gains or losses on settlements of commodity derivatives (but does not include payments for the derivative monetizations in 2021 and 2023). These commodity derivatives do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes.
(4) The average realized price for the years ended December 31, 2022 and 2023 includes $10 million and $15 million, respectively, of proceeds related to a take-or-pay contract. Excluding the effect of these proceeds, the average realized price for ethane before the effects of derivatives for the years ended December 31, 2022 and 2023 would have been $19.88 per Bbl and $9.55 per Bbl, respectively.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we own an interest as of December 31, 2023. A majority of our developed acreage is subject to liens securing the Credit Facility. Approximately 88% of our net Appalachian Basin acreage is held by production. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this table.

	Developed Acres		Undeveloped Acres (2)		Total Acres (2)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Appalachian Basin (1)	274,618	259,498	295,752	255,718	570,370	515,216

(1) Our acreage is located in West Virginia, Ohio and Pennsylvania.
(2) There are 15,996 gross (10,681 net), 6,559 gross (6,264 net) and 4,272 gross (4,288 net) acres subject to expiration during the years ending December 31, 2024, 2025 and 2026, respectively, if production is not established within the spacing units covering the acreage prior to the expiration dates and they are not otherwise extended or renewed.

Productive Wells

As of December 31, 2023, we had 1,798 gross and 1,637 net productive wells, all of which are natural gas wells located in the Appalachian Basin. Net wells reflect the sum of our percentage ownership in gross wells.

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2021, 2022 and 2023. Gross wells reflect the number of wells in which we own an interest and include historical drilling activity in the Appalachian Basin. Net wells reflect the sum of our working interests in gross wells.

	Year Ended December 31,					
	2021		2022		2023 (1)	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	66	57	71	58	87	70
Dry	—	—	—	—	—	—
Total development wells	66	57	71	58	87	70
Exploratory wells:						
Productive	2	2	1	1	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	2	2	1	1	—	—

(1) Well counts exclude 23 gross wells (19 net wells) that were in the process of being completed as of December 31, 2023.

Gathering and Compression

The substantial majority of our exploration and development activities are supported by the natural gas gathering and compression assets of Antero Midstream. As a result, our agreements with Antero Midstream allow us to obtain the necessary gathering and compression capacity for our production, and we have leveraged our relationship with Antero Midstream to support our development. Antero Midstream's capital expenditures for the years ended December 31, 2022 and 2023 for gas gathering and compression infrastructure that services our production were $209 million and $132 million, respectively. Subject to pre-existing dedications and other third-party commitments, we have dedicated to Antero Midstream substantially all of our current and future acreage in West Virginia and Ohio for gathering and compression services.

As of December 31, 2023, Antero Midstream's gathering and compression systems included 631 miles of gas gathering pipelines and 4.5 Bcf/d of compression capacity in the Appalachian Basin. We also have access to additional third-party low pressure and high pressure pipelines, and we utilized three additional third-party compressor stations. The gathering, compression and dehydration services provided by third parties are contracted on a fixed-fee basis.

Natural Gas Processing

Many of our wells in the Appalachian Basin allow us to produce liquids-rich natural gas that contains a significant amount of NGLs. Liquids-rich natural gas is processed, which involves the removal and separation of NGLs from the wellhead natural gas.

NGLs are valuable commodities once removed from the natural gas stream in a cryogenic processing facility yielding y-grade liquids. Y-grade liquids are then fractionated, thereby breaking up the y-grade liquid into its key components. Fractionation refers to the process by which a y-grade stream is separated into individual products such as ethane, propane, normal butane, isobutane and natural gasoline. Fractionation occurs by heating the y-grade liquids to allow for the separation of the component parts based on the specific boiling points of each product. Each of the individual products has its own market price.

The combination of infrastructure constraints in the Appalachian Basin and low ethane prices has resulted in many producers "rejecting" rather than "recovering" ethane. Ethane rejection occurs when ethane is left in the wellhead gas stream when the gas is processed, rather than being extracted and sold as a liquid after fractionation. When ethane is left in the gas stream, the Btu content of the residue gas at the tailgate of the processing plant is higher. Producers generally elect to "reject" ethane when the price received for the ethane in the gas stream is greater than the net price received for the ethane being sold as a liquid after fractionation. When ethane is recovered, the Btu content of the residue gas is lower, but a producer is then able to recover the value of the ethane sold as a separate product.

Given the existing commodity price environment and the current limited ethane market in the northeast, we are currently rejecting the majority of the ethane obtained in the natural gas stream when processing our liquids-rich gas. However, we realize a pricing upgrade when selling the remaining NGLs product stream at current prices. We may elect to recover more ethane when ethane prices result in a value for the ethane that is greater than the Btu equivalent residue gas and incremental recovery costs.

We contract with MarkWest to provide cryogenic processing capacity for our Appalachian Basin production. Antero Midstream owns a 50% interest in the Joint Venture to develop processing and fractionation assets in Appalachia. Below is a summary of the nameplate capacity of the processing plants owned by MarkWest and the Joint Venture, our contracted capacity at these plants and their completion status.

	Plant Processing Nameplate Capacity (MMcf/d)	**Contracted Processing Capacity (MMcf/d)**	**Completion Status**
Sherwood 1 through 13 (1)	2,600	2,600	In service
Smithburg 1 (1)	200	200	In service
Seneca 1 through 4 (1)	800	600	In service
Total	3,600	3,400	

(1) MarkWest owns the gas processing plants referred to as Sherwood 1 through 6 and Seneca 1 through 4 and the Joint Venture owns the gas processing plants referred to as Sherwood 7 through 13 and Smithburg 1. The Joint Venture also owns a 33 1/3% interest in two fractionation facilities located at MarkWest's Hopedale complex.

Transportation and Takeaway Capacity

We have entered into firm transportation agreements with various pipelines that enable us to deliver natural gas to the Midwest, Gulf Coast, Eastern Regional, and Mid-Atlantic markets. Our primary firm transportation commitments include the following:

Midwest-Chicago Regional Markets

We have several firm transportation contracts with pipelines that have capacity to deliver natural gas to the Chicago and Michigan markets. The Chicago directed pipelines include the Rockies Express Pipeline ("REX"), the Midwestern Gas Transmission pipeline ("MGT"), the Natural Gas Pipeline Company of America pipeline ("NGPL"), and the ANR Pipeline Company pipeline ("ANR Chicago"). The firm transportation contract on REX provides firm capacity for 400,000 MMBtu/d and delivers gas to downstream contracts on MGT, NGPL and ANR Chicago.

We have 125,000, 75,000 and 200,000 MMBtu/d of firm transportation on MGT, NGPL and ANR Chicago, respectively. The MGT and NGPL contracts deliver gas to the Chicago city gate area and the ANR Chicago contract delivers natural gas to Chicago in the summer and Michigan in the winter. The Chicago and Michigan contracts expire at various dates from 2029 through 2033.

Gulf Coast, Atlantic Seaboard and International Markets

We have firm transportation contracts with various pipelines to access the Gulf Coast, Atlantic Seaboard and international markets. These contracts include firm capacity on the following pipelines: (i) Columbia Gas Transmission Pipeline ("TCO"), (ii) Columbia Gulf Transmission Pipeline ("Columbia Gulf"), (iii) Stonewall Gas Gathering ("SGG"), (iv) Tennessee Gas Pipeline ("Tennessee"), (v) ANR Pipeline ("ANR Gulf"), (vi) Rover Pipeline ("Rover"), (vii) Texas Eastern Transmission Corp. - M2 Zone ("TETCO M2"), (viii) Mountaineer Xpress Pipeline ("MXP"), (ix) Columbia Gas Transmission IPP Pool ("TCO IPP"), (x) Gulf Xpress Pipeline ("GXP"), (xi) Enterprise Products Partners ATEX Pipeline ("ATEX") and (xii) Sunoco Pipeline ("Mariner East 2"). Our diverse portfolio of firm capacity gives us the flexibility to move natural gas to the local Appalachia market or other preferred markets with more favorable pricing. These firm capacity contracts include:

- TCO firm capacity of approximately 453,000 MMBtu/d. Of the 453,000 MMBtu/d of firm capacity on TCO, we have the ability to utilize 430,000 MMBtu/d on Columbia Gulf, which provides access to the Gulf Coast markets. These contracts expire at various dates from 2024 through 2028.

- SGG firm capacity of 900,000 MMBtu/d, which increases to 940,000 MMBtu/d for a portion of 2024, that transports gas from various gathering system interconnection points and the MarkWest Sherwood plant complex to the TCO WB System. Our SGG firm capacity decreases to 600,000 MMBtu/d in 2027. Additionally, we have firm transportation contracts with TCO for both the western and eastern directions on the pipeline. Our firm capacity of 720,000 MMBtu/d, which increases to 746,000 MMBtu/d in 2024 and 800,000 MMBtu/d in 2027, west bound on TCO ("TCO WB") provides us access to the local Appalachia and the Gulf Coast markets via the Columbia Gulf or Tennessee pipelines. Our firm capacity of 330,000 MMBtu/d east bound on TCO delivers natural gas to the Cove Point LNG facility. These contracts expire at various dates from 2030 through 2038.

- Tennessee firm capacity of 790,000 MMBtu/d, which decreases to 200,000 MMBtu/d in 2030, to deliver natural gas from the Broad Run interconnect on TCO WB to the Gulf Coast market. This contract expires at various dates from 2030 to 2033.

- ANR Gulf firm capacity of 600,000 MMBtu/d to deliver natural gas from West Virginia and Ohio to the Gulf Coast market. This contract expires in 2045.

- Rover Pipeline firm capacity of 840,000 MMBtu/d, which decreases to 800,000 MMBtu/d in 2025, that connects the Appalachian Basin to Midwest and Gulf Coast markets via the ANR Chicago and ANR Gulf segments. These contracts expire in 2025 and 2033.

- MXP firm capacity of 700,000 MMBtu/d to deliver (i) approximately 517,000 MMBtu/d to TCO IPP, which continues to Leach, Kentucky and (ii) approximately 183,000 MMBtu/d to GXP, which continues to the Gulf Coast. These contracts expire at various dates from 2024 to 2058.

- ATEX firm capacity of 20,000 Bbl/d to deliver ethane to Mont Belvieu, Texas. This contract expires in 2028.

- Mariner East 2 firm capacity for ethane of 11,500 Bbl/d and propane and butane of 65,000 Bbl/d to deliver to Marcus Hook, Pennsylvania. These contracts expire in 2028 and 2029, respectively. Mariner East 2 provides access to international markets via trans-ocean LPG carriers.

Under firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. See Note 14—Commitments to the consolidated financial statements for information on our minimum fees for such contracts. Based on current projected 2024 annual production guidance, we estimate that we could incur annual net marketing costs of \$0.04 per Mcfe to \$0.06 per Mcfe in 2024 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third-party gas and capture positive basis differentials. Where permitted, we continue to actively market any excess capacity in order to offset minimum commitment fees and those activities are recorded in our net marketing expense.

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell gas and NGLs. We believe we will have sufficient production quantities to meet substantially all of such commitments. We may purchase gas from third parties to satisfy shortfalls should they occur.

As of December 31, 2023, our firm sales commitments through 2028 included:

Year Ending December 31,	Natural Gas (MMBtu/d)	Ethane (Bbl/d)	C3+ NGLs (Bbl/d)
2024	602,620	100,250	16,549
2025	600,000	85,500	1,250
2026	600,000	85,250	—
2027	600,000	86,500	—
2028	600,000	86,500	—

We utilize a part of our firm transportation capacity to deliver gas and NGLs under the majority of these firm sales contracts. We have firm transportation contracts that require us to either ship products on said pipelines or pay demand charges for shortfalls. The minimum demand fees are reflected in our table of contractual obligations. See Note 14—Commitments to the consolidated financial statements.

Water Handling Operations

Our agreements with Antero Midstream allow us to obtain fresh water for use in our drilling and completion operations, as well as services to dispose of flowback and produced water resulting from our operations.

Antero Midstream owns two independent fresh water distribution systems that distribute fresh water from the Ohio River and several regional water sources, for well completion operations in the Appalachian Basin. These systems consist of permanent buried pipelines, portable surface pipelines and water storage facilities, as well as pumping stations to transport the water throughout the pipeline networks. The surface pipelines are moved to well pads to service completion operations to the extent necessary and feasible. Through Antero Midstream, we also recycle and reuse the majority of our flowback and produced water through blending.

As of December 31, 2023, Antero Midstream owned and operated 232 miles of buried water pipelines and 146 miles of portable surface water pipelines in the Appalachian Basin. Additionally, as of December 31, 2023, Antero Midstream had the ability to store 5.5 million barrels of fresh water in 36 impoundments equipped with transfer pumps located throughout our leasehold acreage.

Major Customers

Our sales to Six One Commodities LLC accounted for 10% and 12% of our total sales for the years ended December 31, 2021 and 2022, respectively. No customer accounted for more than 10% of our sales for the year ended December 31, 2023.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, often in the case of undeveloped properties and acquisitions of producing properties, cursory investigation of record title is made at the time of such acquisitions. Further investigations may be made before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value of, the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under natural gas leases; or
- net profits interests.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, cold winters, hot summers or severe weather events can significantly increase demand and price fluctuations, while seasonal anomalies, such as mild winters, mild summers or severe weather events can sometimes lessen the impact of these fluctuations. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the spring, summer and fall. This can also reduce seasonal demand fluctuations. Seasonal anomalies can also increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit, and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state, and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Regulation of the Oil and Natural Gas Industry

General

We operate on private or state-owned lands, and we have no production from federal mineral interests. Our oil and natural gas operations are subject to extensive, and frequently changing, laws and regulations related to well permitting, drilling and completion, and to the production, transportation and sale of natural gas, NGLs and oil. We believe compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, such laws and regulations are frequently amended or reinterpreted. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, federal agencies, state and local governments and the courts. We cannot predict when or whether any such proposals may become effective. Therefore, we are unable to predict the future costs or impact of compliance. The regulatory burden on the industry increases the cost of doing business and affects profitability. We do not believe that any regulatory changes will affect us materially differently from the way they will affect our competitors.

Regulation of Production of Natural Gas and Oil

We own interests in properties located onshore in West Virginia, Ohio and Pennsylvania, and our production activities on these properties are subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. These statutes and regulations address requirements related to permits for drilling of wells, bonding to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, the plugging and abandonment of wells, venting or flaring of natural gas and the ratability or fair apportionment of production from fields and individual wells. In addition, all of the states in which we own and operate properties have regulations governing environmental and conservation matters, including provisions for the handling and disposing or discharge of waste materials, the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, and the size of drilling and spacing units or proration units and the density of wells that may be drilled. Some states also have granted their oil and gas regulators the power to prorate production to the market demand for oil and gas, and other states may elect to do so in the future. The effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, NGLs and oil within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation of Natural Gas

The transportation and sale, or resale, of natural gas in interstate commerce are regulated by the FERC, under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA"), and regulations issued under those statutes. 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. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. 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.

Gathering services, which occurs upstream of jurisdictional transmission services, are regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC. Although FERC has not made any formal determinations with respect to any of our facilities, 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. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be 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 such 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 varies 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 any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those 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.

Regulation of Sales of Natural Gas, NGLs and Oil

The prices at which we sell natural gas, NGLs and oil are not currently subject to federal regulation and, for the most part, are not subject to state regulation. FERC, however, regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. Similarly, the price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. FERC regulates the transportation of oil and liquids on interstate pipelines under the provision of the Interstate Commerce Act, the Energy Policy Act of 1992 and regulations issued under those statutes. Intrastate pipeline transportation of oil, NGLs and other products, is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. In addition, while sales by producers of natural gas and all sales of crude oil, condensate and NGLs can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

With regard to our physical sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC as described below, the U.S. Commodity Futures Trading Commission under the Commodity Exchange Act ("CEA") and the Federal Trade Commission ("FTC"). We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation. Should we violate the anti-market manipulation laws and regulations, we could be subject to fines and penalties as well as related third-party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

The Domenici Barton Energy Policy Act of 2005 ("EPAct 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, and furthermore, provided FERC with additional civil penalty authority. In Order No. 670, FERC promulgated rules implementing the anti-market manipulation provision of the EPAct of 2005, which make it unlawful to: (i) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (ii) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do 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, which now includes the annual reporting requirements under Order No. 704 described below. Under the EPAct of 2005, FERC has the power to assess civil penalties of up to $1,000,000 (adjusted annually for inflation) per day for each violation of the NGA and the NGPA. In January 2024, FERC issued an order (Order No. 903) increasing the maximum civil penalty amounts under the NGA and NGPA to adjust for inflation. FERC may now assess civil penalties under the NGA and NGPA of up to $1,544,521 per violation per day.

Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

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. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately $1.4 million (adjusted annually for inflation) per violation per day. Together with FERC, these agencies have imposed broad rules and regulations prohibiting fraud and manipulation in oil and gas markets and energy futures markets.

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, and we cannot predict what future action FERC will take. We do not believe that any regulatory changes will affect us materially differently from the way they will affect our competitors.

Regulation of Environmental and Occupational Safety and Health Matters

General

Our operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health and the discharge of materials into the environment or otherwise relating to environmental protection. Violations of these laws can result in substantial administrative, civil and criminal penalties. These laws and regulations may require the acquisition of permits before drilling or other regulated activity commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, completing, producing and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas or areas with endangered or threatened species restrictions, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits, establish specific safety and health criteria addressing worker protection and impose substantial liabilities for pollution resulting from operations or failure to comply with applicable laws and regulations. In addition, these laws and regulations may restrict the rate of production.

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

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act ("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 that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, 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. In addition, despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we generate materials in the course of our operations that may be regulated as hazardous substances based on their characteristics; however, we are unaware of any liabilities arising under CERCLA for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act ("RCRA"), and analogous state laws, establish detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA, or state agencies under RCRA's less stringent nonhazardous solid waste provisions, or under state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as waste solvents, laboratory wastes and waste compressor oils that may become regulated as hazardous wastes if such wastes have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including offsite locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. We are able to control directly the operation of only those wells with respect to which we act or have acted as operator. The failure of a prior owner or operator to comply with applicable environmental regulations may, in certain circumstances, be attributed to us as current owners or operators under CERCLA. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, regardless of fault, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or waste pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (the "CWA"), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). The scope of these regulated waters has been subject to substantial controversy. In 2015 and 2020, respectively, the Obama and Trump Administrations each published final rules attempting to define the federal jurisdictional reach over waters of the United States ("WOTUS"); however, both of these rulemakings were subject to legal challenge. In January 2023, the EPA and Corps published a final rule to establish a definition of WOTUS based on the pre-2015 regulations with updates to incorporate existing Supreme Court decisions and regulatory guidance. However, the January 2023 rule was challenged and is currently enjoined in 27 states. In May 2023, the U.S. Supreme Court released its opinion in Sackett v. EPA, which involved issues relating to the legal tests used to determine whether wetlands qualify as WOTUS. The Sackett decision invalidated certain parts of the January 2023 rule and significantly narrowed its scope, resulting in a revised rule being issued in September 2023. However, due to the injunction on the January 2023 rule, the implementation of the September 2023 rule currently varies by state. In the 27 states, subject to the injunction, the agencies are interpreting the definition of WOTUS consistent with the pre-2015 regulatory regime and the changes made by the Sackett decision, which utilizes the "continuous surface connection" test to determine if wetlands qualify as WOTUS. In the remaining 23 states, the agencies are implementing the September 2023 rule, which did not define the term "continuous surface connection." Therefore, some uncertainty remains as to how broadly the September 2023 rule and the Sackett decision will be interpreted by the agencies. To the extent the implementation of the final rule, results of the litigation, or any action further expands the scope of the CWA's jurisdiction in areas where we operate, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which could delay the development of our natural gas and oil projects. Similarly, any increased costs or delays for such permits may impact the development of pipeline infrastructure, which may impact our ability to transport our products. Also, pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants, the costs of which could be significant. The need to obtain permits has the potential to delay the development of our oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS"), for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards, and completed attainment/non-attainment designations in July 2018. Subsequently, in 2020, the Trump Administration decided to leave this standard in place, but the Biden Administration has announced plans to formally review this decision and consider instituting a more stringent standard. The EPA's reconsideration of this standard remains ongoing. These decisions are subject to legal challenge, and any proposed rule will likely be subject to such challenge as well. The EPA has also issued final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants programs. These final rules require, among other things, capturing or combustion of certain emissions, as well as emission leak detection and repair programs. These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such current requirements will have a material adverse effect on our operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other GHG, present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD"), construction and Title V operating permit reviews for certain large stationary sources that are already major sources of criteria pollutant emissions regulated under the statute. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA for those emissions. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations.

The federal regulation of methane from oil and gas facilities has been subject to substantial uncertainty in recent years. In June 2016, the EPA finalized NSPS, known as Subpart OOOOa, that establish emission standards for methane and volatile organic compounds ("VOCs") from new and modified oil and natural gas production and natural gas processing and transmission facilities. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified and existing oil and gas facilities. Subsequently, the U.S. Congress approved, and President Biden has signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. In response to President Biden's executive order calling on the EPA to revisit federal regulations regarding methane, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc, in December 2023. Under the final rules, states have two years to prepare and submit their plans to impose methane emission controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources. The requirements include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems and zero-emission requirements for certain devices. The rule also establishes a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. It is likely, however, that the final rule and its requirements will be subject to legal challenges. Moreover, compliance with the new rules may affect the amount we owe under the IRA 2022's methane fee described above because compliance with EPA's methane rules would exempt an otherwise covered facility from the requirement to pay the methane fee. The requirements of the EPA's final methane rules have the potential to increase our operating costs and thus may adversely affect our financial results and cash flows. Moreover, failure to comply with these CAA requirements can result in the imposition of substantial fines and penalties as well as costly injunctive relief. Given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities.

We have developed a program to reduce and manage our methane and other air emissions that is guided by the following principles: (i) monitoring the science of climate change and air quality, (ii) addressing stakeholder inquiries regarding our position on climate change, methane emissions and air quality matters, (iii) monitoring our measures to reduce methane and air emissions and (iv) overseeing development of methane and air emission reductions from activities, including implementation of best-management practices and new technology.

For example, Antero incorporated a balanced drill out technique as the final step in the completions process where the majority of gas from the wellbore is maintained downhole. This is followed by a controlled emission flowback process that captures gas and sends it to sales. We have a sustained history of managing methane emissions from our operations, as demonstrated by our continued use of emission reduction techniques and equipment.

When we permit a facility, we install air pollution control equipment to comply with federal Clean Air Act NSPS and applicable Best Available Control Technology standards. The control equipment includes Vapor Recovery Towers and Vapor Recovery Units, which capture methane emissions and direct them to a sales line. This technology allows us to recover a valuable product and reduce emissions. Additionally, residual storage tank emissions are controlled with vapor combustors that reduce methane emissions by 98%. We continue to transition away from intermittent and low bleed natural gas supplied pneumatic devices to air supplied pneumatics at all new production facilities along with limiting natural gas pneumatic releases by routing to a process, sales line or combustion device. In 2023, we eliminated or replaced approximately 500 natural gas driven pneumatic devices, which brings the total number of pneumatic devices eliminated or replaced in our operations to approximately 6,700 since this initiative began in 2021.

Our methane and air emission control program also includes a Leak Detection and Repair ("LDAR") program. Periodic inspections are conducted to minimize emissions by detecting leaks and repairing them promptly. The LDAR program inspections utilize a state-of-the-art Optical Gas Imaging, Forward Looking Infrared Radar camera to identify equipment leaks. In addition, our Operations group has a maintenance program in place, which includes cleaning and replacing thief hatch seals and worn equipment to prevent leaks from occurring. Our efforts to date have resulted in a declining volume of methane emissions based on the decreasing number of leaks detected by our LDAR program.

We participate in the EPA's Natural Gas STAR Program, which provides a framework for companies with U.S. oil and gas operations to implement methane reduction technologies and practices and document their emission reduction activities. We are also members of ONE Future, a voluntary industry collective that seeks to reduce methane emission intensity across the natural gas supply chain, as well as The Environmental Partnership, which focuses on voluntary measures that the oil and gas industry can take to reduce emissions of methane and VOCs through the implementation of LDAR, equipment emission monitoring and maintenance and repair programs. By joining these programs, we committed to: (i) evaluate our methane emission reduction opportunities, (ii) implement methane reduction projects where feasible and (iii) annually report our methane emissions and/or our methane reduction activities.

Since 2017, we have published an annual ESG report, which highlights our most significant environmental program improvements and initiatives. As highlighted in our ESG report, our methane leak loss rate in 2022 was 0.014%, calculated in accordance with ONE Future, well below the ONE Future voluntary industry target of 1%.

During 2023, our GHG/methane emission reduction efforts included the following activities:

- Initiated a responsibly sourced gas certification effort that will expand the number of wells and production that is Trustwell certified by Project Canary.
- Conducted three aerial flyovers of 78 well pad locations as part of our emissions monitoring initiatives.
- Eliminated or replaced approximately 500 intermittent and low-bleed natural gas-controlled pneumatics.
- Plugged and abandoned certain older vertical wells that were acquired in conjunction with property acquisitions. Plugging and abandoning older, low producing wells can reduce methane emissions.
- Preventatively replaced and/or repaired aging storage tank vapor control system equipment to reduce potential for fugitive methane and GHG emissions.
- Continued utilization of the following procedures or equipment in our operations:
    - Quarterly facility LDAR inspections, which is twice the frequency required by current federal regulation.
    - Lockdown thief hatches and isolation valves on storage tanks at all new production facilities to reduce unnecessary potential emissions during daily operations and maintenance activity.
    - Operated burner management systems with two stages of pressure control, which are certified by the manufacturer to meet EPA performance standards, to optimize combustor efficiency.
    - Vapor recovery systems that incorporate up to three stages of vapor recovery in our process.
    - Low pressure separators as part of our completions process to recover methane that would otherwise be flared during flowback operations and allows such methane to become a salable product.
    - Periodic pressure relief valve testing and repair.
    - Balanced-pressure well drill outs, which minimize the potential for venting and/or flaring of gas from our wells during the well completion process.
    - Mobile gas lift units, which reduces emissions that would otherwise be emitted by well swabbing and liquids unloading.
- Held meetings with our ESG Advisory Council comprised of a cross-disciplinary group of internal subject matter experts to partner with our GHG/Methane Reduction Team to manage ESG (including climate change) risks, opportunities and strategies.
- Held quarterly meetings with our GHG/Methane Reduction team comprised of internal subject matter experts to review emerging methane detection and quantification technologies applicable to exploration and production operations.

We continue to assess various opportunities for emission reductions. However, we cannot guarantee that we will be able to implement any of the opportunities that we may review or explore. For any such opportunities that we do choose to implement, we cannot guarantee that we will be able to implement them within a specific timeframe or across all operational assets. For risks and uncertainties related to ESG matters, see “Item 1A. Risk Factors—Business Operations—Increasing attention to ESG matters and conservation measures may adversely impact our business.”

Increasingly, oil and natural gas companies are exposed to litigation risks associated with the threat of climate change. A number of parties have brought suits against oil and natural gas companies in state or federal court for alleged contributions to, or failures to disclose the impacts of, climate change. We are not currently party to any such litigation, but could be named in future actions making similar claims of liability. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

In the United States, no comprehensive climate change legislation has been implemented at the federal level, though recently passed laws such as the IRA 2022 advance numerous climate-related objectives. President Biden has highlighted addressing climate change as a priority of his administration, which includes certain potential initiatives for climate change legislation to be proposed and passed into law. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the oil and natural gas industry, and increased emphasis on climate-related risks across agencies and economic sectors. Additionally, in November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen and sustainable biofuels; and reducing non-CO2 GHG emissions, such as methane and nitrous oxide. Other actions that could be pursued by the Biden Administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. For example, on January 26, 2024, President Biden announced a temporary pause on pending decisions on new exports of LNG to countries that the United States does not have free trade agreements with, pending Department of Energy review of the underlying analyses for authorization. The pause is intended to provide time to integrate certain considerations, including potential energy cost increases for consumers and manufacturers and the latest assessment of the impact of GHG emissions, and to ensure adequate guards against health risks are in place. In August 2022, the IRA 2022 was signed into law, appropriating significant federal funding for renewable energy initiatives and, for the first time ever, imposing a federal fee on excess methane emissions from certain oil and gas facilities. The emissions fee and renewable and low-carbon energy funding provisions of the law could increase our operating costs and accelerate the transition away from oil and natural gas, which could in turn adversely affect our business and results of operations. Internationally, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. President Biden recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change ("COP26"), during which multiple announcements were made, including a call for parties to eliminate certain oil and natural gas subsidies and pursue further action on non-CO2 GHGs. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. These goals were reaffirmed at the 27th Conference of the Parties ("COP27") in November 2022, and countries were called upon to accelerate efforts towards the phase-out of inefficient fossil fuel subsidies, though no firm commitment or timeline was made. At the 28th Conference of the Parties ("COP28") in December 2023, the parties signed onto an agreement to transition away from fossil fuels in energy systems and increase renewable energy capacity, though no timeline for doing so was set. While non-binding, the agreements coming out of COP28 could result in increased pressure among financial institutions and various stakeholders to reduce or otherwise impose more stringent limitations on funding for and increase potential opposition to the exploration and production of fossil fuels. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, COP28 or other international conventions cannot be predicted at this time.

Additionally, our access to capital may be impacted by climate change policies. Financial institutions may adopt policies that have the effect of reducing the funding provided to the oil and natural gas industry. Many of the largest U.S. banks have made net zero commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those emissions. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing and/or underwriting activities to net zero emissions by 2050. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Additionally, financial institutions may be required to adopt policies that have the effect of reducing the funding provided to the oil and natural gas industry. For example, the Federal Reserve has joined the Network for Greening the Financial System (the "NGFS"), a consortium of financial regulators focused on addressing climate-related risks in the financial sector and, in November 2021, issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. In January 2023, the Federal Reserve released instructions for a pilot climate scenario analysis being undertaken by six of the U.S.'s largest banks, which took place throughout 2023. While we cannot predict what policies may result from this, a material reduction in the capital available to the oil and natural gas industry could make it more difficult to secure funding for exploration, development, production, transportation and processing activities, which could impact our business and operations.

In addition, the SEC has proposed a rule requiring registrants to include certain climate-related disclosures, including Scope 1, 2 and 3 GHG emissions, climate-related targets and goals, and certain climate-related financial statement metrics, in registration statements and periodic reports. The final rule is expected in the second quarter of 2024. We cannot predict the final form and substance of the rule. Similarly, in October 2023, the Governor of California signed the Climate Corporate Data Accountability Act

("CCDAA") and Climate-Related Financial Risk Act ("CRFRA") into law. The CCDAA requires both public and private U.S. companies that are "doing business in California" and that have a total annual revenue of $1 billion to publicly disclose and verify, on an annual basis, Scope 1, 2 and 3 GHG emissions. The CRFRA requires the disclosure of a climate-related financial risk report (in line with the Task Force on the Climate-Related Financial Disclosures ("TCFD") recommendations or equivalent disclosure requirements under the International Sustainability Standards Board's ("ISSB") climate-relate disclosure standards) every other year for public and private companies that are "doing business in California" and have total annual revenue of at least $500 million. Reporting under both laws would begin in 2026. Currently, the ultimate impact of these laws on our business is uncertain. The Governor of California has directed further consideration of the implementation deadlines for each of the laws, and there is potential for legal challenges to be filed with respect to the scope of the law, but, absent clarification or revisions to the law, alongside the SEC proposed rule, finalization and implementation may result in additional costs to comply with these disclosure requirements as well as increased costs of and restrictions on access to capital. Separately, enhanced climate-related disclosure requirements could lead to reputational or other harm with customers, regulators, investors or other stakeholders and could also increase our litigation risks relating to statements alleged to have been made by us or others in our industry regarding climate change risks, or in connection with any future disclosures we may make regarding reported emissions, particularly given the inherent uncertainties and estimations with respect to calculating and reporting GHG emissions. To the extent the rules impose additional reporting obligations, we could face increased costs. Separately, the SEC has also from time to time applied additional scrutiny to existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer's existing climate disclosures to be misleading or deficient.

Moreover, climate change may also result in various physical risks, such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns, that could adversely impact our financial condition and operations, as well as those or our suppliers and customers. Such physical risks may result in damage to our facilities or otherwise adversely impact our operations, such as if we become subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact the infrastructure we rely on to produce or transport our products. One or more of these developments could have a material adverse effect on our business, financial condition, and operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations, as does most of the domestic oil and natural gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act ("SDWA"), over certain hydraulic fracturing activities. For example, although we do not use diesel fuel down hole in our hydraulic fracturing operations, in February 2014, the EPA issued permitting guidance for the industry regarding such activities. In addition, the EPA finalized rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. New legislation regulating hydraulic fracturing may be considered again in future, though we cannot predict when or the scope of any such legislation at this time. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, the Ohio Legislature has adopted a law requiring oil and natural gas operators to disclose chemical ingredients used to hydraulically fracture wells and to conduct pre-drill baseline water quality sampling of certain water wells near a proposed horizontal well. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have banned and others seek to ban hydraulic fracturing altogether. We believe that we are in compliance with the applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities, and citizens. We do not believe that any noncompliance with worker health and safety requirements has occurred or will have a material adverse effect on our business or operations.

Endangered Species Act

The federal Endangered Species Act ("ESA"), provides for the protection of endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on natural gas and oil leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service ("USFWS"), may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for natural gas and oil development. Moreover, as a result of a settlement, the USFWS was required to make a determination as to whether more than 250 species classified as endangered or threatened should be listed under the ESA by the completion of the agency's 2017 fiscal year. For example, in November 2022, the USFWS listed the northern long-eared bat, whose habitat includes the areas in which we operate, as an endangered species under the ESA, which became effective on March 31, 2023. The designation of previously unprotected species as threatened or endangered, or redesignation of a threatened species as endangered, in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2023, nor do we anticipate that such expenditures will be material in 2024.

Human Capital

We believe that our employees and contractors are significant contributors to our success and the future success of our Company, which depends on our ability to attract, retain and motivate qualified personnel. The skills, experience and industry knowledge of key employees significantly benefit our operations and performance.

As of December 31, 2023, we had 604 full-time employees, including 45 in executive, finance, treasury, legal and administration, 19 in information technology, 17 in geology, 240 in production and operations, 177 in midstream and water, 55 in land and 51 in accounting and internal audit. Additionally, we utilize the services of independent contractors to perform various field and other services. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be generally good.

Total Rewards

We have demonstrated a history of investing in our workforce by offering competitive salaries, fair living wages and comprehensive benefits. To foster a stronger sense of ownership and align the interests of our personnel with shareholders, we provide long-term incentive programs that include restricted stock units, performance share units and cash awards. Additionally, we offer short-term cash incentive programs, which are discretionary and are based on individual and company performance factors, among others. Furthermore, we offer comprehensive benefits to our full-time employees working 30 hours or more per week. To be an employer of choice and maintain the strength of our workforce, we consistently assess the current business environment and labor market to refine our compensation and benefits programs and other resources available to our personnel. Among other benefits, these include:

- comprehensive health insurance, including vision and dental; we have not increased employee premiums in over 16 years;
- employee Health Savings Accounts, including contributions to these accounts by us;
- 401(k) retirement savings plan with discretionary contribution matching opportunities;
- competitive paid time off and sick leave programs;

- paid parental leave;
- student loan repayment matching opportunities; and
- wellness support benefits including an employee assistance program, short-term and long-term disability coverage and gym memberships and/or fitness subscription reimbursement, among others.

Role Based Support

We support our employees' professional development. To help our personnel succeed in their roles, we emphasize continuous formal and informal training, developmental and educational opportunities. We also assist employees with the cost of educational pursuits through our student loan repayment matching program. Additionally, we have a robust performance evaluation program, which includes tools to facilitate goals and career progression.

Workforce Health and Safety

The safety of our employees is a core tenet of our values, and our safety goal is zero incidents and zero injuries. A strong safety culture reduces risk, enhances productivity and builds a strong reputation in the communities in which we operate. We have earned a reputation as a safe and an environmentally responsible operator through continuous improvement in our safety performance. This makes us more attractive for current and new employees.

We invest in safety training and coaching, promote risk assessments and encourage visible safety leadership. Employees are empowered and expected to stop or refuse to perform a job if it is not safe or cannot be performed safely. We sponsor emergency preparedness programs, conduct regular audits to assess our performance and celebrate our successes in which we acknowledge employees and contractors alike who have exhibited strong safety leadership during the course of the year. These many efforts combine to create a culture of safety throughout the company and provide a positive influence on our contractor community.

Diversity, Inclusion and Workplace Culture

We are committed to building a culture where diversity and inclusion are core philosophies across our operations. We embrace an approach that values diversity, and we are also committed to making opportunities for development and progress available to all employees so their talents can be fully developed to maximize our and their success. We believe that creating an environment that cultivates a sense of belonging requires encouraging employees to continue to educate themselves about each other's experiences, and we strive to promote the respect and dignity of all persons. We also believe it is important that we foster education, communication and understanding about diversity, inclusion and belonging. Finally, in line with our commitments to equal employment opportunity and diversity and inclusion, we expect recruiters operating on our behalf to provide us with a diverse pool of candidates.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 1615 Wynkoop Street, Denver, Colorado 80202 and our telephone number is (303) 357-7310. Our website is located at *www.anteroresources.com*.

We furnish or file our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and amendments to such reports and other documents with the SEC under the Exchange Act. The SEC also maintains an internet website at *www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC.

We also make these documents available free of charge at *www.anteroresources.com* under the "Investors" link as soon as reasonably practicable after they are filed or furnished with the SEC.

Information on our website is not incorporated into this Annual Report on Form 10-K or our other filings with the SEC and is not a part of them.

ITEM 1A. RISK FACTORS

We are subject to certain risks and hazards due to the nature of the business activities we conduct. The risks described in this Annual Report on Form 10-K could materially and adversely affect our business, financial condition, cash flows and results of operations. We may experience additional risks and uncertainties not currently known to us. Furthermore, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect our business, financial condition, cash flows and results of operations.

Commodity Prices

Natural gas, NGLs and oil price volatility, or a substantial or prolonged period of low natural gas, NGLs and oil prices, may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our natural gas, NGLs and oil production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas, NGLs and oil;
- the price and quantity of imports of foreign, and exports of domestic, oil, natural gas and NGLs including liquefied natural gas;
- political conditions in or affecting other producing countries, including conflicts in or among the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- events that impact global market demand;
- prevailing prices on local price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $3.78 per MMBtu to a low of $1.74 per MMBtu in 2023, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $96.37 per barrel to a low of $66.61 per barrel during the same period. While oil and natural gas prices were substantially lower in 2023 than they were in 2022, the markets for these commodities have historically been volatile, and these markets will likely continue to be volatile in the future. In addition, the market price for natural gas in the Appalachian Basin continues to be lower relative to NYMEX Henry Hub as a result of the significant increases in the supply of natural gas in the Northeast region in recent years. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, which adds further volatility to the pricing of NGLs. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas, oil and NGLs at our ultimate sales points and, thus, cannot predict the ultimate impact of prices on our operations.

Prolonged low, and/or significant or extended declines in, natural gas, NGLs and oil prices may adversely affect our revenues, operating income, cash flows and financial position, particularly if we are unable to control our development costs during periods of lower natural gas, NGLs and oil prices. Declines in prices could also adversely affect our drilling activities and the amount of natural gas, NGLs and oil that we can produce economically, which may result in our having to make significant downward adjustments to the value of our assets and could cause us to incur non-cash impairment charges to earnings in future periods. Reductions in cash flows from lower commodity prices have required us to reduce our capital spending and could reduce our production and our reserves, negatively affecting our future rate of growth. Lower prices for natural gas, NGLs and oil may also adversely affect our credit ratings and result in a reduction in our borrowing capacity and access to other capital. We are also exposed to the risk of non-performance by our hedge counterparties in the event that changes, positive or negative, in natural gas prices result in our derivative contracts having a positive fair value in our favor. Further, adverse economic and market conditions could negatively affect the collectability of our trade receivables and cause our hedge counterparties to be unable to perform their obligations or to seek bankruptcy protection.

Increases in natural gas, NGLs and oil prices may be accompanied by or result in increased well drilling costs, increased production taxes, increased lease operating expenses, increased volatility in seasonal gas price spreads and increased end-user conservation or conversion to alternative fuels. In addition, to the extent we have hedged our current production at prices below the current market price, we are unable to benefit fully from an increase in the price of natural gas, NGLs and oil.

Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, we have historically entered into fixed swap hedging contracts for a significant percentage of our expected production volumes. For example, in 2021 we hedged 91%, 36% and 29% of our natural gas, NGLs and oil production, respectively. Additionally, in 2022 we hedged 49% of our natural gas production, and our NGLs and oil production was unhedged. Due to our improved liquidity and leverage position as compared to past levels, the percentage of our expected production that we hedge has decreased. For example, in 2023, we hedged 1% of our natural gas production through fixed swaps , and our NGLs and oil production was unhedged, and as of December 31, 2023, we do not have any fixed swap contracts. To the extent that we engage in hedging activity in the future, we may be prevented from realizing the near-term benefits of price increases above the levels of the hedges. If we choose not to engage in, or otherwise reduce our future use of, hedging arrangements or are unable to engage in hedging arrangements due to lack of acceptable counterparties, we may be more adversely affected by changes in commodity prices than our competitors who engage in hedging arrangements to a greater extent than we do. Conversely, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production volumes are less than expected;
- commodity prices rise significantly in excess of our hedged price, resulting in significant cash payments to our hedge counterparties;
- we are unable to find available counterparties in the future;
- the creditworthiness of our hedge counterparties or their guarantors is substantially impaired; or
- counterparties have credit limits that may constrain our ability to hedge additional volumes.

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 will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment if the estimated future undiscounted cash flows are less than the carrying value of our properties. 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, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur significant impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Imbalances between the supply of and demand for oil, natural gas and NGLs could cause extreme market volatility, increased costs and decreased availability of storage capacity.

The marketing of our natural gas, NGLs and oil production is substantially dependent upon the existence of adequate markets for our products. Imbalances between the supply of and demand for these products could cause extreme market volatility and a substantial adverse effect on commodity prices during such time. Such imbalances could also result in the industry experiencing storage capacity constraints with respect to certain NGLs and oil. Without sufficient transportation and storage capacity, many producers may be forced to temporarily shut in portions of their production or sell portions of their production at below-market prices.

For example, in response to the coronavirus pandemic, governments tried to slow the spread of the virus by imposing social distancing guidelines, travel restrictions and stay-at-home orders, among other actions, which caused a significant decrease in the demand for oil and to a lesser extent, natural gas and NGLs. We are unable to predict the extent to which another world health event could impact our business results and operations, but such events could give rise to an imbalance between the supply of and demand for our products that could adversely affect our financial condition and results of operations.

Reserves

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

As of December 31, 2023, 24% of our total estimated proved reserves were classified as proved undeveloped. Our 4.3 Tcfe of estimated proved undeveloped reserves will require an estimated $1.8 billion of development capital over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices 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 require us to reclassify our proved undeveloped reserves as unproved reserves.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and gas reserves 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 our estimated quantities and present value of our reserves.

To prepare our estimates, we must project production rates and 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 realized prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, realized prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

Investors should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

The standardized measure of discounted future net cash flows from our proved reserves is not the same as the current market value of our estimated oil and gas reserves.

Investors should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we based the discounted future net cash flows from our proved reserves on the twelve-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our properties will be affected by factors such as the actual prices we receive for natural gas, NGLs and oil, the amount, timing and cost of actual production and changes in governmental regulations or taxation. In addition, the 10% discount factor we use when calculating the standardized measure is based on SEC guidelines, and may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and, eventually, production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore, our future cash flow and results of operations are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production, and any such acquisition and development may be offset by any asset disposition. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Approximately 50% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Approximately 50% of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. We have proved undeveloped reserves of 337 Bcfe related to such acreage that is subject to renewal prior to drilling. In addition, 12% of our natural gas leases related to our Appalachian Basin acreage require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage. For more information on our future potential acreage expirations, see "Item 1. Business and Properties—Our Properties and Operations—Undeveloped Acreage Expirations."

Business Operations

Drilling for and producing oil and 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 exploration, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable hydrocarbons. Our decisions to purchase, explore or develop prospects 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 "—Reserves—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is subject to operational uncertainties.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- prolonged declines in natural gas, NGLs and oil prices;
- limitations in the market for natural gas, NGLs and oil;
- delays imposed by, or resulting from, compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of, or delays in, obtaining equipment, qualified personnel or water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions, such as blizzards, tornadoes, hurricanes and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- limited availability of financing at acceptable terms; and
- mineral interest or other title problems.

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

Properties that we decide to drill may not yield natural gas, NGLs or oil in commercially viable quantities, which may adversely affect our financial condition, results of operations and cash flows.

Prior to drilling and testing a prospect, we are unable to predict with certainty whether any particular prospect will yield natural gas, NGLs or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. Seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in commercial quantities. We cannot make any assurances that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- mineral interest or other title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, or shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

Market conditions or operational impediments, such as the unavailability of satisfactory transportation arrangements or necessary infrastructure, may hinder our access to natural gas, NGLs and oil markets or delay our production.

The availability of a ready market for our natural gas, NGLs and oil production depends on a number of factors, including the demand for and supply of natural gas, NGLs and oil and the proximity of reserves to, and capacity of, pipelines, other transportation facilities, gathering and processing, fractionation facilities and the availability of other third-party transportation services. The capacity of transmission, gathering and processing and fractionation facilities and the availability of third-party transportation services may be insufficient to accommodate potential production from existing and new wells, which may result in substantial discounts in the prices we receive for our natural gas, NGLs and oil. While our investment in midstream infrastructure through Antero Midstream is intended to address access to and potential curtailments on existing midstream infrastructure, we also deliver to and are serviced by third-party natural gas, NGLs and oil transmission, gathering, processing, storage and fractionation facilities and transportation services that are limited in number, geographically concentrated and subject to significant risks. These risks include the availability of capital, materials and qualified contractors and work force, as well as weather conditions, natural gas, NGLs and oil price volatility, delays in obtaining permits and other government approvals, title and property access problems, geology, public opposition to infrastructure development, compliance by Antero Midstream and/or third parties with their contractual obligations to us and other factors.

An extended interruption of access to or service from pipelines and facilities operated by Antero Midstream and/or third parties, or of transportation services provided by Antero Midstream and/or third parties for any reason, including our failure to obtain such services on acceptable terms, cyberattacks on such pipelines and facilities or service interruptions due to gas quality, could materially harm our business by causing delays in producing and selling our natural gas, NGLs and oil. In such an event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at prices lower than market prices or at prices lower than we currently project, all of which could adversely affect our business, financial condition and results of operations. If we shut-in or curtail production for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

Our ability to produce natural gas, NGLs and oil economically and in commercial quantities is dependent on the availability of adequate supplies of water for drilling and completion operations and access to water and waste disposal or recycling facilities and services at a reasonable cost. Restrictions on our ability to obtain water or dispose of produced water and other waste may have an adverse effect on our financial condition, results of operations and cash flows.

The hydraulic fracture stimulation process on which we depend to produce commercial quantities of natural gas, NGLs and oil requires the use and disposal of significant quantities of water. The availability of water recycling facilities and other disposal alternatives to receive all of the water produced from our wells may affect our production. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, or to timely obtain water sourcing permits or other rights, could adversely impact our operations. The availability of water may change over time in ways that we cannot control, including as a result of climate change-related effects such as shifting weather patterns. Additionally, the imposition of new environmental initiatives and regulations could include restrictions on our ability to obtain water or dispose of waste and adversely affect our business and operating results.

Our identified potential well locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to obtain the substantial amount of capital necessary to drill our potential well locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our development strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas, NGLs and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, unitization agreements, lease acquisitions, surface agreements, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas, NGLs or oil from these or any other potential well locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified. For more information on our future potential acreage expirations, see "Item 1. Business and Properties—Our Properties and Operations—Undeveloped Acreage Expirations."

As of December 31, 2023, we had 1,588 identified potential horizontal well locations in our proved, probable and possible reserve base. As a result of the limitations described above, we may be unable to drill many of our potential well locations. In addition, we will require significant additional capital over a prolonged period to pursue the development of these locations, and we may not be able to obtain or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves, or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified potential well locations, see "Item 1. Business and Properties—Our Properties and Operations—Estimated Proved Reserves—Identification of Potential Well Locations."

We may incur losses as a result of title defects or other matters affecting the unitization of interests.

When we acquire oil and gas leases or interests, we typically do not incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, before attempting to acquire a lease in a specific mineral interest, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office. Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due to the long history of private land ownership, severed mineral estates and inadequate records of death and heirships regarding mineral and surface land ownership in the area, resulting in extensive and complex chains of title. The existence of a material title deficiency can render a lease worthless and can adversely affect our financial condition, results of operations and cash flows. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title or the right to include certain interests in a unit may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property, which may adversely impact our business, financial condition or results of operations.

Legal proceedings brought against us could result in substantial liabilities and materially and adversely impact our financial condition.

Like many oil and gas companies, we are involved in various legal proceedings, including threatened claims, such as contractual, title and royalty disputes. For example, we are party to class action litigation that involves claimants' alleged entitlements to, and accounting for, natural gas royalties, and that could have an impact on the methods for determining the amount of permitted post-production costs and types of cost that may be deducted from royalty payments, among other things. The cost to settle legal proceedings (asserted or unasserted) or satisfy any resulting unfavorable judgment against us in such proceedings could result in a substantial liability or the loss of interests, which could materially and adversely impact our cash flows, operating results and financial condition for the period in which any such effect becomes reasonably estimable. Judgments and estimates to determine accruals or range of losses related to legal proceedings are difficult to predict and could change from one period to the next, and such changes could be material. Current accruals may be insufficient to satisfy any such judgments. Legal proceedings could also result in negative publicity about the Company. Defending these actions, especially purported class actions, can be costly and can distract management and other personnel from their primary responsibilities. In addition, many of our proceedings are in their early stages. Where this is the case, the allegations and damage theories have not been fully developed, and are all subject to inherent uncertainties. As a result, management's view of the likelihood of a material and adverse financial impact from any such proceeding may change in the future. See Note 15—Contingencies to the consolidated financial statements for more information on legal proceedings.

Increasing attention to ESG matters and conservation measures may adversely impact our business.

Increasing attention to climate change, societal expectations on companies to address climate change, investor, regulatory and societal expectations regarding voluntary and mandatory ESG disclosures and consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, negative impacts on our stock price and reduced access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us. To the extent that societal pressures or regulatory or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are 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. Mandatory ESG-related disclosure is also emerging as an area where we may be, or may become, subject to required disclosures in certain jurisdictions, depending on our purported nexus to such jurisdictions and any such mandatory disclosures may similarly necessitate the use of hypothetical, projected or estimated data, some of which is not controlled by us and is inherently subject to imprecision. Disclosures reliant upon such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. In addition, we have established a net zero goal by 2025 with respect to our Scope 1 (direct) and Scope 2 (indirect from the purchase of energy) GHG emissions, and we could face unexpected material costs as a result of our efforts to meet this goal and any future revisions to it. We continue to evaluate a range of technology and other measures, such as carbon offsets, that could assist with meeting this goal. Given uncertainties related to the use of emerging technologies, the state of markets for and the availability of verified carbon offsets, we cannot predict whether or not we will be able to timely meet these goals, if at all. In addition, while we may seek to only purchase carbon offsets verified by reputable third parties, we cannot guarantee that any carbon offsets we purchase will achieve the GHG emission reductions represented, and we could face increased costs to purchase additional carbon offsets to cover any gap or loss, particularly if carbon offset markets face capacity constraints as a result of increased demand. Moreover, certain stakeholders may object to the use of offsets generally or with respect to specific transactions we engage in as to any carbon reduction benefits we may claim resulting from such offsets. Furthermore, certain jurisdictions, including California, are instituting new laws that require disclosures related to voluntary carbon offsets and similar constructs. Disclosures under these regimes are novel and it is uncertain whether any disclosures we may make in connection therewith will satisfy the laws and may lead to uncertain consequences, such as private parties criticizing such projects, whether via litigation or otherwise. While we may participate in various voluntary frameworks and certification programs to improve the ESG profile of our operations and products, we cannot guarantee that such participation or certification will have the intended results on our or our products' ESG profile. Also, despite any aspirational goals, we may receive pressure from investors, lenders or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles.

Furthermore, our reputation, as well as our stakeholder relationships, could be adversely impacted as a result of, among other things, any failure to meet our ESG plans or goals or stakeholder perceptions of statements made by us, our employees and executives, agents, or other third parties or public pressure from investors or policy groups to change our policies. Such statements with respect to ESG matters are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential ESG benefits. As a result, we may face increased litigation risks from private parties and governmental authorities related to our ESG efforts. Moreover, any alleged claims of greenwashing against us or others in our industry may lead to negative sentiment towards our company or industry. To the extent that the Company is unable to respond timely and appropriately to any negative publicity, our reputation could be harmed. Damage to our overall reputation could have a negative impact on our financial results and require additional resources for the Company to rebuild its reputation. 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 may be used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets 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. Also, institutional lenders may decide not to provide funding for oil and natural gas companies or the corresponding infrastructure projects based on climate change related concerns, which could affect our access to capital for potential growth projects. Moreover, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively or recruit or retain employees, which may adversely affect our operations. Such ESG matters may also impact Antero Midstream and our customers, which may adversely impact our business, financial condition or results of operations.

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, results of operations and cash flows.

Our oil and gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting natural gas and oil related facilities and infrastructure.

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Competition in the oil and gas industry is intense, making it more difficult for us to acquire properties, market products and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing products and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel may increase substantially in the future. We may not be successful in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities and repayment of indebtedness, are challenging, and our failure to appropriately allocate capital and resources among our various initiatives may adversely affect our financial condition.

Our future success depends on whether we can identify optimal strategies for our business. In developing our 2024 business plan, we considered allocating capital and other resources to various aspects of our businesses, including well development, exploratory activities, corporate items, repayment of indebtedness and other alternatives. Notwithstanding the determinations made in the development of our 2024 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, including the appropriate corporate structure or the appropriate rate of reserve development, or fail to optimize our capital investment and capital raising opportunities and to use our other resources to further our business strategies, our financial condition may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2024 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

We periodically engage in acquisitions, dispositions and other strategic transactions, including joint ventures. These transactions involve various inherent risks, such as our ability to obtain the necessary regulatory approvals; the timing of and conditions imposed upon us by regulators in connection with such approvals; the assumption of potential environmental or other liabilities; and our ability to realize the benefits expected from the transactions. In addition, prevailing market conditions and other factors could negatively impact the benefits we receive from transactions. Competition for acquisition opportunities in our industry is intense and may increase the cost of, or cause us to refrain from, completing acquisitions. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our financial position, results of operations and cash flows.

World health events may materially adversely affect our business.

World health events may cause disruptions to our business and operational plans, which may include (i) shortages of employees, (ii) unavailability of contractors and subcontractors, (iii) interruption of supplies from third parties upon which we rely, (iv) recommendations of, or restrictions imposed by, government and health authorities, including quarantines, and (v) restrictions that we and our contractors and subcontractors impose, including facility shutdowns, to ensure the safety of employees and others. While it is not possible to predict their extent or duration, these disruptions may have a material adverse effect on our business, financial condition and results of operations.

Further, the effects of a world health event could negatively impact global demand for crude oil and natural gas, which may contribute to price volatility that could impact the price we receive for natural gas, NGLs and oil and materially and adversely affect the demand for and marketability of our production, as well as lead to temporary curtailment or shut-ins of production due to lack of downstream demand or storage capacity. Additionally, to the extent a pandemic, epidemic or outbreak of an infectious disease adversely affects our business and financial results, it may also have the effect of heightening many of the other risks set forth in this "Item 1A. Risk Factors."

Terrorist attacks, cyberattacks and threats could have a material adverse effect on our business, financial condition and results of operations.

Terrorist attacks or cyberattacks may significantly affect the energy industry, including our operations and those of our suppliers and customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Cyber incidents, including deliberate attacks, have increased in frequency globally. Strategic targets, such as energy related assets, may be at greater risk of future attacks than other targets in the United States. We depend on digital technology in many areas of our business and operations, including, but not limited to, estimating quantities of oil and natural gas reserves, processing and recording financial and operating data, oversight and analysis of our drilling, completion and production operations and communications with our employees and third-party customers or service providers. We also collect and store sensitive data in the ordinary course of our business, including personally identifiable information as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders. 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 cyberattacks, security breaches or unauthorized access. Despite our security measures, our information technology systems may undergo cyberattacks or security breaches including as a result of employee error, malfeasance or other threat vectors, which could lead to the corruption, loss, or disclosure of proprietary and sensitive data, misdirected wire transfers, and an inability to: perform services for our customers; complete or settle transactions; maintain our books and records; prevent environmental damage; and maintain communications or operations. Significant liability to the Company or third parties may result. We are not able to anticipate, detect or prevent all cyberattacks, particularly because the methodologies used by attackers change frequently or may not be recognized until an attack is already underway or significantly thereafter, and because attackers are increasingly using technologies specifically designed to circumvent cybersecurity measures and avoid detection. Cybersecurity attacks are also becoming more sophisticated and include, but are not limited to, ransomware, credential stuffing, spear phishing, social engineering, use of deepfakes (e.g., highly realistic synthetic media generated by artificial intelligence) and other attempts to gain unauthorized access to data for purposes of extortion or other malfeasance.

Our information and operational technologies, systems and networks, and those of our vendors, suppliers, customers and other business partners, may become the target of cyberattacks or information security breaches that result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or adversely disrupt our business operations. Although we have written policies and procedures for monitoring cybersecurity risk and identifying and reporting incidents, there can be no guarantee they will be effective at preventing cyberattacks or ensuring incidents are timely identified or reported. Advances in computer capabilities, discoveries in the field of artificial intelligence, cryptography, or other developments may result in a compromise or breach of the technology we use to safeguard confidential, personal or other information. As cyberattacks 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 cyberattacks. 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 cyberattack or security breach could result in liability resulting from data privacy or cybersecurity claims, liability under data privacy laws, regulatory penalties, damage to our reputation, long-lasting 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 cyberattacks; however, there can be no assurance that we will not suffer such losses in the future. No security measure is infallible. 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.

Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Appalachian Basin in West Virginia and Ohio. As of December 31, 2023, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by, and costs associated with, governmental regulation, state and local political activities, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of natural gas, NGLs or oil.

In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations. For example, third parties may engage in subsurface coal and other mining operations near or under our properties, which could cause subsidence or other damage to our properties, adversely impact our drilling operations or adversely impact third-party midstream activities on which we rely. In such event, our operations may be impaired or interrupted, and we may not be able to recover the costs incurred as a result of temporary shut-ins or the plugging and abandonment of any of our wells. Furthermore, the existence of mining operations near our properties could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. These restrictions on our operations, and any similar restrictions, could cause delays or interruptions or prevent us from executing our business strategy, which could materially adversely affect our results of operations and financial position.

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.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Opposition toward oil and natural gas drilling and development activities generally has been growing globally and is particularly pronounced in the U.S., and companies in our industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental matters, sustainability and business practices. Negative public perception regarding us and/or our industry may lead to increased litigation and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new local, state and federal laws, regulations, guidelines and enforcement interpretations in safety, environmental, royalty and surface use areas. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. 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 need to conduct our operations to be withheld, delayed, challenged or burdened by requirements that restrict our ability to profitably conduct our business. In addition, anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations, such as drilling and development. If activism against oil and natural gas exploration and development persists or increases, there could be a material adverse effect on our business, financial condition and results of operations.

Customer Concentration and Credit Risk

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our natural gas, NGLs and oil production that we market to energy companies, end users, and refineries ($384 million as of December 31, 2023). We are also subject to credit risk due to concentration of receivables with several significant customers. The largest purchaser of our products during the year ended December 31, 2023 accounted for 9% of our product revenues. We do not require all 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.

Hedging transactions may become more costly or unavailable to us and expose us to counterparty credit risk.

To the extent that we engage in hedging activity in the future, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, NGLs and oil, which could also have an adverse effect on our financial condition. If natural gas, NGLs or oil prices upon settlement of our derivative contracts exceed the price at which we have hedged our commodities, we will be obligated to make cash payments to our hedge counterparties, which could, in certain circumstances, be significant.

In addition, U.S. regulators adopted a final rule in November 2019 implementing a new approach for calculating the exposure amount of derivative contracts under the applicable agencies' regulatory capital rules, referred to as the standardized approach for counterparty credit risk ("SA-CCR"). As adopted, certain financial institutions are required to comply with the new SA-CCR rules beginning on January 1, 2022. These rules could significantly increase the capital requirements for certain participants in the over-the-counter derivatives market in which we participate. These increased capital requirements could result in significant additional costs being passed through to end-users like us or reduce the number of participants or products available to us in the over-the-counter derivatives market. The effects of these regulations could reduce our hedging opportunities, or substantially increase the cost of hedging, which could adversely affect our business, financial condition and results of operations.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil, NGLs and natural gas prices and interest rates.

As described above, we enter into certain derivative instruments in the ordinary course operations of our business. Derivative instruments expose us to the risk of financial loss in some circumstances, including when there is an increase in the differential between the underlying price in the derivative instrument and actual prices received or when there are issues with regard to legal enforceability of such instruments. As of December 31, 2023, the estimated fair value of our total derivative assets was $11 million, and we did not have any derivative assets with bank counterparties under our Credit Facility. Also, our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

Vendor Risks

We are required to pay fees to our service providers based on minimum volumes under long-term contracts regardless of actual volume throughput.

We have various firm transportation and gas processing, gathering and compression service agreements in place, each with minimum volume delivery commitments. Lower commodity prices may lead to reductions in our drilling and completion program, which may result in insufficient production to fully utilize our firm transportation and processing capacity. Our firm transportation agreements expire at various dates from 2024 to 2058 and our gas processing, gathering, and compression services agreements expire at various dates from 2024 to 2038. We are obligated to pay fees on minimum volumes to certain of our service providers regardless of actual volume throughput. In addition, FERC regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. Transportation rates on FERC-regulated pipelines are subject to change, and depending on the amount of any increase, such an increase in rates could have an adverse effect on our results of operations. As of December 31, 2023, our long-term contractual obligations under agreements with minimum volume commitments totaled $10.4 billion over the term of the contracts. If we have insufficient production to meet the minimum volumes or are otherwise unable to fulfill all or a portion of our volume commitments, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results of operations.

Assuming 2024 production is unchanged from 2023 production, we estimate that we will incur annual net marketing costs of $0.05 per Mcfe to $0.07 per Mcfe in 2024 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third-party gas and capture positive basis differentials. Additionally, our net marketing expense could increase depending on utilization of our transportation capacity based on future production and how much, if any, future excess transportation can be marketed to third parties.

We may be limited in our ability to choose gathering operators, processing and fractionation services providers and water services providers in our areas of operations pursuant to our agreements with Antero Midstream.

Pursuant to our gathering and compression agreements with Antero Midstream, we have dedicated the gathering and compression of all of our current and future natural gas production in West Virginia, Ohio and Pennsylvania to Antero Midstream, so long as such production is not otherwise subject to a pre-existing dedication. Further, pursuant to the right of first offer agreement that we have entered into with Antero Midstream, Antero Midstream has a right to bid to provide certain processing and fractionation services in respect of all of our current and future gas production (as long as it is not subject to a pre-existing dedication) and will be entitled to provide such services if its bid matches or is more favorable to us than terms proposed by other parties. As a result, we will be limited in our ability to use other gathering and compression operators in West Virginia, Ohio and Pennsylvania, even if such operators can offer us more efficient service. We will also be limited in our ability to use other processing and fractionation services providers in any area to the extent Antero Midstream is able to offer a competitive bid.

Pursuant to the Water Services Agreement that we have entered into with Antero Midstream, we have dedicated the provision of fresh water and wastewater services in defined service areas in Ohio and West Virginia to Antero Midstream. Additionally, the Water Services Agreement provides Antero Midstream with a right of first offer on any future areas of operation outside of those defined areas. As a result, we will be limited in our ability to use other water services providers in the dedication areas of Ohio and West Virginia or other future areas of operation, even if such providers can offer us more favorable pricing or more efficient service.

The unavailability or high cost of additional drilling rigs, completion services, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill and complete wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, as the rate of inflation has increased in the U.S., the cost of the good and services and labor we use in our operations has also increased, increasing our operating costs.

Interruptions in operations at facilities that process and fractionate our gas, or with pipelines or other facilities that transport or handle our gas, may adversely affect our business, financial condition and results of operations.

We have agreements with processing and fractionation facilities, including those owned by MPLX, LP and the Joint Venture, to accommodate our current operations as well as future development plans. In addition, we have gathering, compression, transportation and similar agreements with third parties to accommodate our current operations as well as future development plans. Any significant interruptions at these facilities or pipelines could cause us to curtail our future development and production plans, which could adversely affect our business, financial condition and results of operations.

The operations of the processing facilities or pipelines could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within the operator's nor our control, such as:

- unscheduled maintenance or catastrophic events, including damages to facilities, related equipment and surrounding properties caused by earthquakes, tornadoes, hurricanes, floods, fires, severe weather, explosions and other natural disasters;

- restrictions imposed by governmental authorities or court proceedings;

- labor difficulties that result in a work stoppage or slowdown;
- disruption in the supply of power, water and other resources necessary to operate the facilities;
- damage to the facilities resulting from NGLs that do not comply with applicable specifications;
- inadequate fractionation capacity or market access to support production volumes, including lack of availability of rail cars, barges, trucks and pipeline capacity, or market constraints, including reduced demand or limited markets for certain NGLs; and
- terrorist attacks or cyberattacks.

While such interruptions are outside of our control, we cannot predict if our counterparties will, in any such cases, attempt to recover certain damages, whether or not they are entitled to them, which could be substantial.

Acquisitions, Divestitures and Takeovers

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

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

The accuracy of these assessments is inherently uncertain. 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 fully assess 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” basis. Even if we are able to obtain contractual indemnification rights, there is no assurance that the seller will be capable of performing under any indemnification obligation.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business.

In the future, we may acquire businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to effectively integrate the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to successfully integrate the acquired businesses and assets into our existing operations or to minimize any unforeseen operational difficulties could have a material adverse effect on our business, financial condition and results of operations.

In addition, the agreements governing our debt impose certain limitations on our ability to enter into mergers or combination transactions. Such agreements also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Certain 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. Among other things, our certificate of incorporation and bylaws:

- provide advance notice procedures with regard to stockholder nominations of candidates for election as directors or other stockholder proposals to be brought before meetings of our stockholders, which may preclude our stockholders from bringing certain matters before our stockholders at an annual or special meeting;

- provide our Board of Directors the ability to authorize issuance of preferred stock in one or more series, which makes it possible for our Board of Directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us and which may have the effect of deterring hostile takeovers or delaying changes in control or management of us;

- provide that the authorized number of directors may be changed only by resolution of our Board of Directors;

- provide that, subject to the rights of holders of any series of preferred stock to elect directors or fill vacancies in respect of such directors as specified in the related preferred stock designation, all vacancies, including newly created directorships be filled by the affirmative vote of holders of a majority of directors then in office, even if less than a quorum, or by the sole remaining director, and will not be filled by our stockholders;

- provide that, subject to the rights of the holders of any series of preferred stock to elect directors under specified circumstances, if any, any action required or permitted to be taken by our stockholders must be effected at a duly called annual or special meeting of our stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders;

- provide for our Board of Directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three-year terms;

- provide that, subject to the rights of the holders of shares of any series of preferred stock, if any, to remove directors elected by such series of preferred stock pursuant to our certificate of incorporation (including any preferred stock designation thereunder), directors may be removed from office at any time, only for cause and by the holders of a majority of the voting power of all outstanding voting shares entitled to vote generally in the election of directors;

- provide that special meetings of our stockholders may only be called by the Chief Executive Officer, the Chairman of our Board of Directors or our Board of Directors pursuant to a resolution adopted by a majority of the total number of directors that we would have if there were no vacancies;

- provide that (i) Yorktown Partners LLC ("Yorktown") and their affiliates are permitted to participate (directly or indirectly) in venture capital and other direct investments in corporations, joint ventures, limited liability companies and other entities conducting business of any kind, nature or description, (ii) Yorktown and their affiliates are permitted to have interests in, participate with, aid and maintain seats on the boards of directors or similar governing bodies of any such investments, in each case that may, are or will be competitive with our business and the business of our subsidiaries or in the same or similar lines of business as us and our subsidiaries, or that could be suitable for us or our subsidiaries and (iii) we have, subject to limited exceptions, renounced, to the fullest extent permitted by law, any interest or expectancy in, or in being offered an opportunity to participate in, such corporate opportunities;

- provide that the provisions of our certificate of incorporation can only be amended or repealed by the affirmative vote of the holders of at least 66 2/3% in voting power of the outstanding shares of our common stock entitled to vote thereon, voting together as a single class; and

- provide that our bylaws can be altered or repealed by (a) our Board of Directors or (b) our stockholders upon the affirmative vote of holders of at least 66 2/3% of the voting power of our common stock outstanding and entitled to vote thereon, voting together as a single class.

We have elected not to be subject to the provisions of Section 203 of the Delaware General Corporation Law (the "DGCL"), regulating corporate takeovers.

In general, the provisions of Section 203 of the DGCL prohibit a Delaware corporation, including those whose securities are listed for trading on the New York Stock Exchange, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- prior to such time, the business combination or the transaction which resulted in the stockholder becoming an interested stockholder is approved by our Board of Directors;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced (excluding certain specified shares); or

- on or after such time the business combination is approved by our Board of Directors and authorized at a meeting of stockholders by the holders of at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Section 203 of the DGCL permits a Delaware corporation to elect not to be governed by the provisions of Section 203. Pursuant to our certificate of incorporation, we expressly elected not to be governed by Section 203. Accordingly, we are not subject to any anti-takeover effects or protections of Section 203 of the DGCL, although no assurance can be given that we will not elect to be governed by Section 203 of the DGCL pursuant to an amendment to our certificate of incorporation in the future.

Certain of our stockholders have investments in our affiliates that may conflict with the interests of other stockholders.

Paul M. Rady and an individual affiliated with Yorktown serve as members of our Board of Directors and the Board of Directors of Antero Midstream. Mr. Rady and Yorktown also own a significant portion of the shares of our common stock. As a result of their investments in Antero Midstream, Mr. Rady and Yorktown may have conflicting interests with other stockholders. Conflicts of interest could arise in the future between us, on the one hand, and Mr. Rady and Yorktown, on the other hand, regarding, among other things, decisions related to our financing, capital expenditures and business plans, the terms of our agreements with Antero Midstream and its subsidiaries and the pursuit of potentially competitive business activities or business opportunities.

Provisions of our 2026 Convertible Notes could delay or prevent an otherwise beneficial takeover of us.

Certain provisions of our 2026 Convertible Notes and the indenture governing such notes could make a third party attempt to acquire us more difficult or expensive. For example, if a takeover constitutes a "Fundamental Change" (as defined in the indenture governing such notes), then holders of our 2026 Convertible Notes will have the right to require us to repurchase their 2026 Convertible Notes for cash. In addition, if a takeover constitutes a "Make-Whole Fundamental Change" (as defined in such indenture), then we may be required to temporarily increase the conversion rate. In either case, and in other cases, our obligations under the 2026 Convertible Notes and the indenture governing such notes could increase the cost of acquiring us or otherwise discourage a third party from acquiring us, including in a transaction that holders of our 2026 Convertible Notes or holders of our common stock may view as favorable.

We may be unable to dispose of assets on attractive terms and may be required to retain liabilities for certain matters.

Our business and financing plans may periodically include divesting certain assets. However, we do not completely control the timing of divestitures, and delays in completing divestitures may reduce the benefits we may receive from them, such as reducing management distractions by selling non-core assets and the receipt of cash proceeds that reduce debt and contribute to our liquidity. Various factors could materially affect our ability to dispose of assets if and when we decide to do so, including the availability of purchasers willing to purchase the assets at prices acceptable to us, particularly in times of reduced and volatile commodity prices. In connection with certain dispositions, we may be required to contractually indemnify the purchaser or retain liabilities for certain matters.

Capital Structure and Access to Capital

Our exploration and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our oil and gas reserves.

The oil and gas industry is capital intensive. We make, and expect to continue to make, substantial capital expenditures for the exploration, development, production, and acquisition of oil and gas reserves. Our cash flow used in investing activities for 2023 included drilling and completion costs of $964 million and leasehold expenditures of $151 million. Our net capital budget for 2024 is $725 million to $800 million. Our budget includes: a range of $650 million to $700 million for drilling and completion and $75 million to $100 million for leasehold expenditures. Our capital budget excludes acquisitions, except for leasehold acquisitions. We expect to fund these capital expenditures with cash generated by operations, and dividends from Antero Midstream, which we do not control the timing or amount of, if any; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The actual amount and timing of our future capital expenditures may differ materially from our capital budget as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological, and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to maintain production. For additional discussion of the risks regarding our ability to obtain funding, read "—The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility."

The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves;
- the value of our commodity derivative portfolio; and
- our ability to borrow under the Credit Facility.

If our revenues or the borrowing base under the Credit Facility decrease as a result of sustained periods of low natural gas, NGLs and oil 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 at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flows generated by our operations or available borrowings under the Credit Facility are 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 properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

We may not be able to generate sufficient cash flows to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on, or to refinance, our indebtedness, including the Credit Facility, our Senior Notes and our 2026 Convertible Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the Senior Notes and 2026 Convertible Notes.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness, including the Senior Notes. For example, the proceeds of our asset sale program were used to retire a portion of our indebtedness. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets, including the market for debt securities, and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including the indentures governing our Senior Notes and our 2026 Convertible Notes, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness and may result in us having to post collateral with, or provide letters of credit to, certain transactional counterparties. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. The Credit Facility and the indentures governing our Senior Notes and our 2026 Convertible Notes place certain restrictions on our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility.

The borrowing base under the Credit Facility is currently $3.5 billion, and lender commitments under the Credit Facility are $1.6 billion. Our borrowing base is redetermined semi-annually by the lenders each April and October based on certain factors, including our reserves and hedge position, with the next borrowing base redetermination scheduled to occur in April 2024. Our borrowing base may decrease as a result of a decline in natural gas, NGLs or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which could have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

In addition, a downgrade to our credit rating could require us to post additional collateral in the form of letters of credit or cash as financial assurance of our performance under certain contractual arrangements, such as pipeline transportation contracts. An increase in our outstanding letters of credit may impact our available liquidity under our Credit Facility.

We may be unable to access the equity or debt capital markets to meet our obligations.

Declines in commodity prices may cause the financial markets to exert downward pressure on stock prices and credit capacity for companies throughout the energy industry. For example, for portions of 2020, the market for senior unsecured notes was unfavorable for high-yield issuers such as us. Our development plan may require access to the capital and credit markets. Although the market for high-yield debt securities has improved compared to 2020, if the high-yield market deteriorates, or if we are unable to access alternative means of debt or equity financing on acceptable terms or at all, we may be unable to implement our development plan or otherwise carry out our business plan, which could have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

The Credit Facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness), including restrictive covenants that may limit our ability to, among other things:

- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The indentures governing our Senior Notes contain similar restrictive covenants. In addition, the Credit Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indentures governing our Senior Notes and our 2026 Convertible Notes, may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing our Senior Notes and 2026 Convertible Notes, and the Credit Facility impose on us.

The Credit Facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the oil and natural gas properties and commodity derivatives securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the Credit Facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. For additional discussion of the risks regarding our ability to obtain funding under the Credit Facility, see "—The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility."

A breach of any covenant in the Credit Facility would result in a default under that agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, during 2023, we had average outstanding borrowings under the Credit Facility of $342 million, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased interest expense for that period of $3 million and a corresponding decrease in our cash flows and net income before the effects of income taxes. Furthermore, a downgrade to our credit rating would trigger certain obligations to deliver letters of credit to certain transactional counterparties, which would adversely impact our available liquidity. Disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. A significant reduction in net cash provided by operating activities or the availability of credit could materially and adversely affect our ability to achieve our development plan and operating results.

We may be unable to raise the funds necessary to repurchase the 2026 Convertible Notes for cash following a fundamental change, or to pay any cash amounts due upon conversion, and our other indebtedness may limit our ability to repurchase the 2026 Convertible Notes or pay cash upon their conversion.

Holders of our 2026 Convertible Notes may, subject to a limited exception, require us to repurchase their 2026 Convertible Notes following a fundamental change at a cash repurchase price generally equal to 100% of the principal amount of the 2026 Convertible Notes to be repurchased, plus accrued and unpaid interest, if any. In addition, upon conversion, we will satisfy part or all of our conversion obligation in cash unless we elect to settle conversions solely in shares of our common stock. We may not have enough available cash or be able to obtain financing at the time we are required to repurchase the 2026 Convertible Notes or pay the cash amounts due upon conversion. In addition, applicable law, regulatory authorities and the agreements governing our other indebtedness, may restrict our ability to repurchase the 2026 Convertible Notes or pay the cash amounts due upon conversion. Our inability to satisfy our obligations under the 2026 Convertible Notes could affect the trading price of our common stock.

Our failure to repurchase the 2026 Convertible Notes or to pay the cash amounts due upon conversion when required will constitute a default under the indenture governing the 2026 Convertible Notes. A default under this indenture or the occurrence of the fundamental change itself could also lead to a default under agreements governing our other indebtedness, which may result in that other indebtedness becoming immediately payable in full. We may not have sufficient funds to satisfy all amounts due under the other indebtedness and the 2026 Convertible Notes.

Compliance with Regulations

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations, as does most of the domestic oil and natural gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding such activities. In addition, the EPA finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. New legislation regulating hydraulic fracturing may be considered again in future, though we cannot predict when or the scope of any such legislation at this time. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, the Ohio legislature has adopted a law requiring oil and natural gas operators to disclose chemical ingredients used to hydraulically fracture wells and to conduct pre-drill baseline water quality sampling of certain water wells near a proposed horizontal well. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have banned and others seek to ban hydraulic fracturing altogether. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, regional, state and local laws and regulations relating to protection of the environment and occupational health and workplace safety, including regulations and enforcement policies that have tended to become increasingly strict over time resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and occupational health and workplace safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters. For example, we have been named as the defendant in separate lawsuits in West Virginia in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties. Also, new laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

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

Our oil and gas exploration, production, processing and transportation operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production, processing and transportation of natural gas, NGLs and oil. For example, President Biden has made action on environmental matters, and climate change in particular, a focus of his administration, and our operations may be subject to greater environmental, health and safety restrictions, particularly with regards to hydraulic fracturing, permitting and GHG emissions. For more information on these matters, see "Item 1. Business and Properties—Regulation of the Oil and Natural Gas Industry—Regulation of Environmental and Occupational Safety and Health Matters." Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Changes to existing or new regulations may unfavorably impact us. Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. Although the FERC has not made any formal determinations with respect to any of our facilities, 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 has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis. Therefore, the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress, and such increased regulation could cause our revenues to decline and operating expenses to increase, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EPAct of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,544,521 per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The Inflation Reduction Act could accelerate the transition to a low carbon economy and could impose new costs on our operations.

In August 2022, President Biden signed the IRA 2022 into law. The IRA 2022 contains hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and carbon capture and sequestration, amongst other provisions. In addition, the IRA 2022 imposes the first ever federal fee on the emission of greenhouse gases through a methane emissions charge. The IRA 2022 amends the federal Clean Air Act to impose a fee on the emission of methane from sources required to report their GHG emissions to the EPA, including those sources in the onshore petroleum and natural gas production and gathering and boosting source categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year after. Calculation of the fee is based on certain thresholds established in the IRA 2022. The methane charge and the incentives for renewable energy infrastructure development could impose additional costs on our operations and further accelerate the transition of the economy away from the use of oil and natural gas towards lower- or zero-carbon emissions alternatives. This could decrease demand for oil and gas and consequently adversely affect our business and results of operations.

Our operations are subject to a series of risks related to climate change that could result in increased operating costs, limit the areas in which we may conduct oil and natural gas exploration and production activities, and reduce demand for our products.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, President Biden has highlighted addressing climate change as a priority of his administration, which includes certain potential initiatives for climate change legislation to be proposed and passed into law. Moreover, federal regulators, state and local governments, and private parties have taken (or announced that they plan to take) actions that have or may have a significant influence on our operations. For example, in response to findings that emissions of carbon dioxide, methane and other GHGs endanger public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA for those emissions. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations.

The federal regulation of methane from oil and gas facilities has been subject to substantial uncertainty in recent years. In June 2016, the EPA finalized NSPS, known as Subpart OOOOa, that establish emission standards for methane and VOCs from new and modified oil and natural gas production and natural gas processing and transmission facilities. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified and existing oil and gas facilities. Subsequently, the U.S. Congress approved, and President Biden has signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. In response to President Biden's executive order calling on the EPA to revisit federal regulations regarding methane, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc, in December 2023. Under the final rules, states have two years to prepare and submit their plans to impose methane emission controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources. The requirements include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems and zero-emission requirements for certain devices. The rule also establishes a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. It is likely, however, that the final rule and its requirements will be subject to legal challenges. Moreover, compliance with the new rules may affect the amount we owe under the IRA 2022's methane fee described above because compliance with EPA's methane rules would exempt an otherwise covered facility from the requirement to pay the methane fee. The requirements of the EPA's final methane rules have the potential to increase our operating costs and thus may adversely affect our financial results and cash flows. Moreover, failure to comply with these CAA requirements can result in the imposition of substantial fines and penalties as well as costly injunctive relief. Given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility, and several states, including West Virginia and Ohio, have separately imposed or are considering imposing their own regulations on methane emissions from oil and gas production activities.

Internationally, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again in COP26, during which multiple announcements were made, including a call for parties to eliminate certain oil and natural gas subsidies and pursue further action on non-CO2 GHGs. These goals were reaffirmed at COP27 in November 2022. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. At COP28 in December 2023, the parties signed onto an agreement to transition away from fossil fuels in energy systems and increase renewable energy capacity, though no timeline for doing so was set. While non-binding, the agreements coming out of COP28 could result in increased pressure among financial institutions and various stakeholders to reduce or otherwise impose more stringent limitations on funding for and increase potential opposition to the exploration and production of fossil fuels. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, COP28 or other international conventions cannot be predicted at this time. Concern over the threat of climate change has also resulted in increasing political risks in the United States, including climate-change related pledges made by President Biden and other public office representatives. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the oil and natural gas industry and increased emphasis on climate-related risks across agencies and economic sectors. Additionally, in November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO2 GHG emissions, such as methane and nitrous oxide. Other actions that could be pursued include more restrictive requirements for the development of pipeline infrastructure or LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. For example, on January 26, 2024, President Biden announced a temporary pause on pending decisions on new exports of LNG to countries that the United States does not have free trade agreements with, pending Department of Energy review of the underlying analyses for authorization. The pause is intended to provide time to integrate certain considerations, including potential energy cost increases for consumers and manufacturers and the latest assessment of the impact of GHG emissions, and to ensure adequate guards against health risks are in place.

Increasingly, oil and natural gas companies are exposed to litigation risks associated with the threat of climate change. A number of parties have brought suits against oil and natural gas companies in state or federal court for alleged contributions to, or failures to disclose the impacts of, climate change. We are not currently party to any such litigation, but could be named in future actions making similar claims of liability. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Additionally, in response to concerns related to climate change, companies in the oil and natural gas industry may be exposed to increasing financial risks. Financial institutions, including investment advisors and certain sovereign wealth, pension and endowment funds, may elect in the future to shift some or all of their investment into non-oil and natural gas related sectors. Institutional lenders who provide financing to fossil-fuel energy companies have also become more attentive to sustainable lending practices, and some of them may elect in future not to provide funding for oil and natural gas companies. Many of the largest U.S. banks have made net zero commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps quantify and reduce those emissions. In addition, at COP26, the GFANZ announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing and/or underwriting activities to net zero emissions by 2050. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the oil and natural gas industry. For example, the Federal Reserve has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector and, in November 2021, issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. A material reduction in the capital available to the oil and natural gas industry could make it more difficult to secure funding for exploration, development, production, transportation and processing activities, which could result in decreased demand for our products or otherwise adversely impact our financial performance.

In addition, the SEC has proposed a rule requiring registrants to include certain climate-related disclosures, including Scope 1, 2 and 3 GHG emissions, climate-related targets and goals, and certain climate-related financial statement metrics, in registration statements and periodic reports. The final rule is expected in 2024, and we cannot predict the final form and substance of the rule. Similarly, in October 2023, the Governor of California signed the CCDAA and CRFRA into law. The CCDAA requires both public and private U.S. companies that are “doing business in California” and that have a total annual revenue of $1 billion to publicly disclose and verify, on an annual basis, Scope 1, 2 and 3 GHG emissions. The CRFRA requires the disclosure of a climate-related financial risk report (in line with the TCFD recommendations or equivalent disclosure requirements under the ISSB climate-relate disclosure standards) every other year for public and private companies that are “doing business in California” and have total annual revenue of at least $500 million. Reporting under both laws would begin in 2026. Currently, the ultimate impact of these laws on our business is uncertain. The Governor of California has directed further consideration of the implementation deadlines for each of the laws, and there is potential for legal challenges to be filed with respect to the scope of the law, but, absent clarification or revisions to the law, alongside the SEC proposed rule, finalization and implementation may result in additional costs to comply with these disclosure requirements as well as increased costs of and restrictions on access to capital. Separately, enhanced climate related disclosure requirements could lead to reputational or other harm with customers, regulators, investors or other stakeholders and could also increase our litigation risks relating to statements alleged to have been made by us or others in our industry regarding climate change risks, or in connection with any future disclosures we may make regarding reported emissions, particularly given the inherent uncertainties and estimations with respect to calculating and reporting GHG emissions. Separately, the SEC has also from time to time applied additional scrutiny to existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer’s existing climate disclosures misleading or deficient.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives related to climate change or GHG emissions from oil and natural gas facilities could result in increased costs of compliance or costs of consumption, thereby reducing demand for our products. Additionally, political, litigation, and financial risks may result in (i) restriction or cancellation of certain oil and natural gas production activities, (ii) incurrence of obligations for alleged damages resulting from climate change, or (iii) impairment of our ability to continue operating in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

Moreover, climate change may also result in various physical risks such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns, that could adversely impact our financial condition and operations, as well as those of our suppliers or customers. Such physical risks may result in damage to our facilities, or otherwise adversely impact our operations, such as if we become subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact the infrastructure on which we rely to produce or transport our products. One of more of these developments could have a material adverse effect on our business, financial condition and operations. In addition, while our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

Regulations related to the protection of wildlife could adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in our operating areas can be adversely affected by regulations designed to protect various wildlife. For example, following a 2020 court order to reconsider its decision to list the northern long-eared bat as threatened instead of endangered, the USFWS redesignated the bat as endangered in November 2022. The designation of previously unprotected species as threatened or endangered, or redesignation of a threatened species as endangered, in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in constraints on our exploration and production activities. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our sand mine is subject to the Federal Mine Safety and Health Act of 1977 and amending legislation, which impose stringent health and safety standards.

We currently own one sand mine that is operated by a third party and is subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures, operating equipment and other matters. This act, as amended, is a strict liability statute and any failure to comply with such existing or any future standards, or any more stringent interpretation or enforcement thereof, could have a material adverse effect on sand mining operations or otherwise significantly restrict mineral extraction and processing operations.

Human Capital

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel, including Paul M. Rady, our Chairman, Chief Executive Officer and President, could have a material adverse effect on our business, financial condition and results of operations.

Our officers and employees provide services to both us and Antero Midstream.

All of our executive officers and certain other personnel provide corporate, general and administrative services to Antero Midstream and, when providing services to Antero Midstream, are concurrently employed by us and Antero Midstream pursuant to the terms of a services agreement. In addition, certain of our operational personnel are seconded to Antero Midstream pursuant to the terms of a secondment agreement and are concurrently employed by us and Antero Midstream during such secondment. As a result, there could be material competition for the time and effort of the officers and employees who provide services to us and Antero Midstream. If such officers and employees do not devote sufficient attention to the management and operation of our business, our financial results may suffer.

Related Parties

Conflicts of interest will arise from time to time between Antero Midstream and us, and Antero Midstream may favor its own interests to the detriment of us and our stockholders.

All of our officers and certain of our directors are also officers or directors of Antero Midstream. Conflicts of interest will arise between Antero Midstream and us. Our directors and officers who are also directors and officers of Antero Midstream have a fiduciary duty to manage Antero Midstream in a manner that is beneficial to Antero Midstream. In resolving these actual or apparent conflicts of interest, these directors and officers may choose strategies that favor Antero Midstream over our interests and the interests of our stockholders. The resolution of any conflicts of interest between Antero Midstream and its subsidiaries, on one hand, and us and our subsidiaries, on the other, to the extent we can resolve them, may be costly and reduce the amount of time and attention that our directors and officers may spend in operating our business, which, in each case, may adversely affect our business.

Taxes

Our future tax liabilities may be greater than expected if our net operating loss ("NOL") carryforwards are limited, we do not generate expected deductions, or tax authorities challenge our tax positions.

As of December 31, 2023, we have U.S. federal and state NOL carryforwards of $1.0 billion and $1.9 billion, respectively. Some of the U.S. federal NOL carryforwards expire in 2037 while others have no expiration date. We expect to fully utilize our U.S. federal NOL carryforwards prior to expiration. The state NOL carryforwards expire at various dates from 2025 to 2041. We do not expect to utilize certain of these NOL carryforwards due to changes in state tax law. Therefore, we have placed a valuation allowance against $1.5 billion of these state NOL carryforwards. These expectations are based upon assumptions we have made regarding, among other things, our income, capital expenditures and net working capital, and upon our NOL carryforwards not becoming subject to future limitation under Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), or otherwise.

Section 382 generally imposes an annual limitation on the amount of NOL carryforwards that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of such corporation's stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that we were to undergo an ownership change, utilization of our NOL carryforwards would be subject to an annual limitation under Section 382, determined by multiplying the value of our stock at the time of the ownership change by the applicable long-term tax-exempt rate in effect during the month in which the ownership change occurs, subject to certain adjustments, which could result in a portion of our NOL carryforwards expiring prior to their utilization. Any unused annual limitation may be carried over to later years. Any limitation on our ability to utilize our NOL carryforwards against income or gain we generate in the future could increase our future tax liabilities and adversely affect our operating results and cash flows.

Furthermore, we are subject to various complex and evolving U.S. federal, state and local tax laws. U.S. federal, state and local tax laws, policies, statutes, rules, regulations or ordinances could be interpreted, changed, modified or applies adversely to us, in each case, possibly with retroactive effect. Any significant variance in our interpretation of current tax laws, including as result of the release of final Treasury Regulations or other interpretive guidance implementing the Tax Cuts and Jobs Act or the IRA 2022, or a successful challenge of one or more of our tax positions by the IRS or other state or local tax authorities could increase our future tax liabilities and adversely affect our operating results and cash flows.

While we expect to be able to (i) utilize all of our U.S. federal NOL carryforwards, (ii) utilize a portion of our state NOL carryforwards and (iii) generate deductions to offset a portion of our future taxable income, in the event that our NOL carryforwards are subject to future limitation (including due to an ownership change under Section 382), deductions are not generated as expected, or if one or more of our tax positions are successfully challenged by the IRS or other tax authorities (in a tax audit or otherwise), our future tax liabilities may be greater than expected, which could adversely affect our operating results and cash flows.

Changes in tax laws or the interpretation thereof or the imposition of new or increased taxes or fees may increase our future tax liabilities and adversely affect our operating results and cash flows.

From time to time, U.S. federal and state level legislation has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently applicable to natural gas and oil exploration and development companies. Such proposed legislative changes include, but are not limited to, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies and (v) an increase in the U.S. federal income tax rate applicable to corporations. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on natural gas and oil extraction. The passage of any legislation as a result of these proposals and other changes in tax laws or the imposition of new or increased taxes or fees on natural gas and oil extraction could increase our future tax liabilities and adversely affect our operating results and cash flows.

In addition, the IRA 2022 includes, among other things, a corporate alternative minimum tax (the "CAMT"). Under the CAMT, a 15% minimum tax will be imposed on certain financial statement income of "applicable corporations" in taxable years beginning after December 31, 2022. A corporation is generally an applicable corporation subject to CAMT in any taxable year following a taxable year in which the "average annual adjusted financial statement income" of the corporation and certain of its subsidiaries and affiliates exceeds $1 billion for a specified three taxable year period. We were not an applicable corporation subject to CAMT in 2023. Based on current commodity pricing, our interpretation of the CAMT and the IRA 2022 and a number of operational, economic, accounting and regulatory assumptions, we do not expect to become an applicable corporation subject to CAMT in the next three years. If we become an applicable corporation and our CAMT liability is greater than our regular U.S. federal income tax liability for any particular tax year, the CAMT liability would effectively accelerate our future U.S. federal income tax obligations, reducing our cash flows in that year, but provide an offsetting credit against our regular U.S. federal income tax liability in future tax years. As a result, our current expectation is that the impact of the CAMT is limited to potential timing differences in future tax years.

The IRA 2022 also imposes a 1% non-deductible excise tax on the fair market value of any stock repurchased by a publicly traded domestic corporation during any taxable year, with the fair market value of such repurchased stock reduced by the fair market value of certain stock issued by such corporation during such taxable year (such excise tax, the "Stock Buyback Tax"). The Biden Administration has proposed increasing the amount of the Stock Buyback Tax from 1% to 4%; however, it is unclear whether such a change in the amount of the excise tax will be enacted and, if enacted, how soon any such change could take effect. The Stock Buyback Tax first applied to our authorized share repurchase program in the year ended December 31, 2023, and will continue to apply in subsequent taxable years.

The U.S. Department of the Treasury and the Internal Revenue Service are expected to release regulations and interpretive guidance relating to the CAMT and the Stock Buyback Tax, and any significant variance from our current interpretation could result in a change in our analysis of the application of the CAMT and the Stock Buyback Tax to us and its impact on our operations and cash flows.

General Risks

The price of our common stock may be volatile, and you could lose a significant portion of your investment.

The market price of the common stock could be volatile, and holders of common stock may not be able to resell their common stock at or above the price at which they acquired such securities due to fluctuations in the market price of common stock.

Specific factors that may have a significant effect on the market price for our common stock include:

- our operating and financial performance and prospects and the trading price of our common stock;
- the level of any dividends we may declare;
- quarterly variations in the rate of growth of our financial indicators, such as net income and revenues;
- levels of indebtedness;
- changes in revenue or earnings estimates or publication of research reports by analysts;
- speculation by the press or investment community;
- sales of our common stock by other stockholders;
- announcements by us or our competitors of significant contracts, acquisitions, strategic partnerships, joint ventures, securities offerings or capital commitments;
- general market conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- adverse changes in tax laws or regulations; and
- domestic and international economic, legal and regulatory factors related to our performance.

Sales of a substantial amount of shares of our common stock in the public market could adversely affect the market price of our shares.

Sales of a substantial amount of shares of our common stock in the public market or grants to our directors and officers under the AR LTIP, or the perception that these sales or grants may occur, could reduce the market price of shares of our common stock. All of the shares of our common stock are freely tradable without restriction or further registration under the Securities Act, unless the shares are held by any of our "affiliates" as such term is defined in Rule 144 under the Securities Act. We cannot predict the size of future issuances of our common stock or securities convertible into our common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock.

There may be future dilution of our common stock, which could adversely affect the market price of shares of our common stock.

We are not restricted from issuing additional shares of our common stock out of our authorized capital. In the future, we may issue shares of our common stock to raise cash for future activities, acquisitions or other purposes. We may also acquire interests in other companies by using a combination of cash and shares of our common stock or only shares. We have issued or may issue securities convertible into, or exchangeable for, or that represent the right to receive, shares of our common stock. For example, as of December 31, 2023, the 2026 Convertible Notes are convertible at the option of holders. Any sales in the public market of the common stock issuable upon such conversion could adversely affect prevailing market prices of our common stock. In addition, the existence of the 2026 Convertible Notes may encourage short selling by market participants because the conversion of the 2026 Convertible Notes could be used to satisfy short positions, or anticipated conversion of the 2026 Convertible Notes into shares of our common stock could depress the price of our common stock. Any of these events may dilute the ownership interests of our stockholders, reduce our net income per share or have an adverse effect on the price of shares of our common stock.

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, employees or agents.

Our certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware (the "Court of Chancery") will, to the fullest extent permitted by applicable law, be the sole and exclusive forum 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 of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the DGCL, our certificate of incorporation or our bylaws as to which the DGCL confers jurisdiction on the Court of Chancery or (iv) any action asserting a claim against us governed by the internal affairs doctrine, in each such case subject to the Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. The foregoing provision does not apply to claims under the Securities Act, the Exchange Act or any claim for which the U.S. federal courts have exclusive jurisdiction. Any person or entity purchasing or otherwise acquiring or holding any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of certificate of incorporation described in the preceding sentence. This choice of forum provision may limit our stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with it or its directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our certificate of incorporation 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 and results of operations.

We may issue preferred stock, which may have terms that could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes our Board of Directors to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our Board of Directors may determine. The terms of one or more classes or series of our preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of a class or series of our preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of our preferred stock could affect the residual value of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 1C. CYBERSECURITY

Processes for Assessing, Identifying and Managing Cybersecurity Risks

We are continuously assessing and adopting new processes, systems and resources in an effort to make our business safer from cybersecurity threats. We depend on digital technology in many areas of our business and operations, including, but not limited to, estimating quantities of oil and natural gas reserves, processing and recording financial and operating data, oversight and analysis of drilling, completion and production operations and communications with our employees and third-party customers and service providers. We also collect and store sensitive data in the ordinary course of our business, including certain personally identifiable information and proprietary information for our business and that of our customers, suppliers, investors and other stakeholders.

Attacks on our assets or security breaches in our systems or infrastructure could lead to the corruption, loss or unauthorized use of such data, delays in production or delivery of our production to customers, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions or other operational disruptions. We seek to address these risks by safeguarding assets, data and operations through the cybersecurity risk management processes described below:

Risk Assessments

We assess our systems, networks and data infrastructure to identify potential cybersecurity threats and vulnerabilities via continuous automated processes that are complemented by manual processes that are executed on both a routine and ad hoc basis. These processes are designed to prevent, detect and investigate activities and events that could pose a cybersecurity risk or threat to us, and include, but are not limited to, monitoring and evaluating cybersecurity intelligence information published or provided by certain United States federal government agencies as well as private cybersecurity groups. Our risk assessment processes are conducted, monitored and reviewed by our security and compliance team as well as third-party consultants. In addition, we perform cybersecurity tabletop exercises with our information technology ("IT") department throughout the year. We also engage a third-party consultant to conduct an annual penetration test of our systems, networks and data infrastructure to complement our risk assessment processes and activities. These risk assessments help evaluate the likelihood and potential impact of cybersecurity incidents.

Our Chief Administrative Officer ("CAO") oversees these risk assessments and meets regularly with the security and compliance team to review cybersecurity risks and threats, and also participates in our enterprise risk management process. In addition, the Company engages several third-party consultants in connection with the risk assessments, and we have established separate processes and procedures to oversee and identify cybersecurity risks associated with third parties. All third parties involved in our cybersecurity risk assessments are required to provide reports designed to allow us to monitor and assess such third parties' security controls.

We monitor and manage our cybersecurity risk and threat exposure through prioritized remediation efforts. Any cybersecurity risk or threat that requires corrective action is managed by our security and compliance team together with certain business partners and IT specialists, as deemed necessary. Potential solutions are assessed in alignment with risk, business and cybersecurity priorities and our controls and security architecture. Plans to remediate cybersecurity risks are approved and monitored regularly for completion.

Incident Identification and Response

We have implemented a monitoring and detection system, with oversight from our CAO to help promptly identify cybersecurity incidents. In the event of any breach or cybersecurity incident, we have a formal incident response plan designed to provide for immediate action to contain the incident, mitigate the impact and restore normal operations efficiently.

Cybersecurity Training and Awareness

We train our users throughout the year using a wide variety of methods on cybersecurity-related topics, including how to identify and report potential social engineering including phishing through emails, text messages and phone calls. Formal training on cybersecurity practices begins when an employee is hired and is re-administered annually. We also require third-party contractors with access to our systems be trained on these topics. In addition, special training is held both formally and informally for groups that entail higher threat risks.

Policies

Our IT polices are designed to address and manage all aspects of our IT environment, including cybersecurity, and we review and update our policies regularly as part of our risk management processes. We deploy both an internal Protection of Personal

Identifiable Information Policy and a publicly available Privacy Notice to help us understand and respect the privacy of the individuals whose data we have custody over. We monitor our data collection practices, policies and notices in an effort to comply with the evolving nature of applicable data privacy and security laws.

Our cybersecurity risk management processes are integrated into our enterprise risk management program. Cybersecurity threats are understood to be dynamic and intersect with various other enterprise risks. As such, cybersecurity is considered to be an important component of our enterprise risk management approach. Our cybersecurity strategies are based on standard cybersecurity frameworks, including the National Institute of Standards and Technology and the International Organization for Standardization.

Board of Directors' Oversight of Cybersecurity Risks and Management's Role in Assessing and Responding to Cybersecurity Risks

Cybersecurity risks are overseen at the board level through the Audit Committee. Our CAO, together with the security and compliance team, is responsible for the monitoring, assessment and management of cybersecurity risk, and seeks to maintain the security and continuity of our operations. Our CAO oversees the Company's cybersecurity strategy, cybersecurity and data privacy policies, measures and controls, and Board of Directors and Audit Committee communications on cybersecurity matters. Our CAO regularly briefs senior management, the Board of Directors and the Audit Committee on cybersecurity issues as part of our overall enterprise risk management program, including quarterly updates to the Audit Committee, which may include information regarding our exposure to privacy and cybersecurity risks, plans and activities to monitor and mitigate privacy and cybersecurity risks, IT governance policies and programs, including our cybersecurity incident response plan, and legislative and regulatory developments that could impact our privacy and cybersecurity risks. Additionally, our Vice President – Risk Management oversees our enterprise risk management process and apprises the Audit Committee and our Board of Directors of all significant risks facing the Company, including cybersecurity risks.

Our CAO, Aaron S.G. Merrick, has more than 25 years of experience in the technology sector and 16 years of experience in managing cybersecurity risk. Mr. Merrick was named CAO in 2022 and previously served as our Vice President – IT since 2016. Prior to joining Antero, he held IT leadership positions of increasing responsibility at Apache Corporation, including Director of IT from 2006 to 2009 and Vice President of IT from 2009 to 2015. Additionally, Mr. Merrick was President of a computer consulting business from 2002 to 2006, and he also held several positions of increasing responsibility at T-NETIX, Inc., including Vice President of IT, during his tenure from 1995 to 2000. Mr. Merrick graduated from Bob Jones University in 1984 with a Bachelor of Science degree in Accounting.

Impact of Risks from Cybersecurity Threats

As of the date of this Annual Report on Form 10-K, we are not aware of any cybersecurity threats, including as a result of any previous cybersecurity incidents, that have materially affected or are reasonably likely to materially affect us. However, we acknowledge that cybersecurity threats are continually evolving, and the possibility of future discovery of cybersecurity incidents remains. Please see "Item 1A. Risk Factors" for additional information about cybersecurity risks. Despite the implementation of our cybersecurity programs, our security measures cannot guarantee that a cyberattack with significant impact will not occur. A successful attack on our IT systems could have significant consequences to the business. While we devote resources to our security measures to protect our systems and information, these measures cannot provide absolute security. See "Item 1A. Risk Factors" for additional information about the risks to our business associated with a breach or compromise to our information technology systems.

ITEM 3. LEGAL PROCEEDINGS

The information required by this item is included in Note 15—Contingencies to the consolidated financial statements and is incorporated herein.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock

We have one class of common equity outstanding, our common stock, par value $0.01 per share. Our common stock is listed on the New York Stock Exchange and traded under the symbol "AR." On February 9, 2024, our common stock was held by 103 holders of record. The number of holders does not include the shareholders for whom shares of our common stock are held in a "nominee" or "street" name.

Issuer Purchases of Equity Securities

The following table sets forth our share purchase activity for each period presented:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Repurchased as Part of Publicly Announced Plans	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plan ($ in thousands)
October 1, 2023 - October 31, 2023	105,101	$ 27.83	—	$ 1,050,901
November 1, 2023 - November 30, 2023	—	—	—	1,050,901
December 1, 2023 - December 31, 2023	—	—	—	1,050,901
Total	105,101	$ 27.83	—	

(1) The total number of shares purchased includes shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of equity awards held by our employees.

Share Repurchase Program

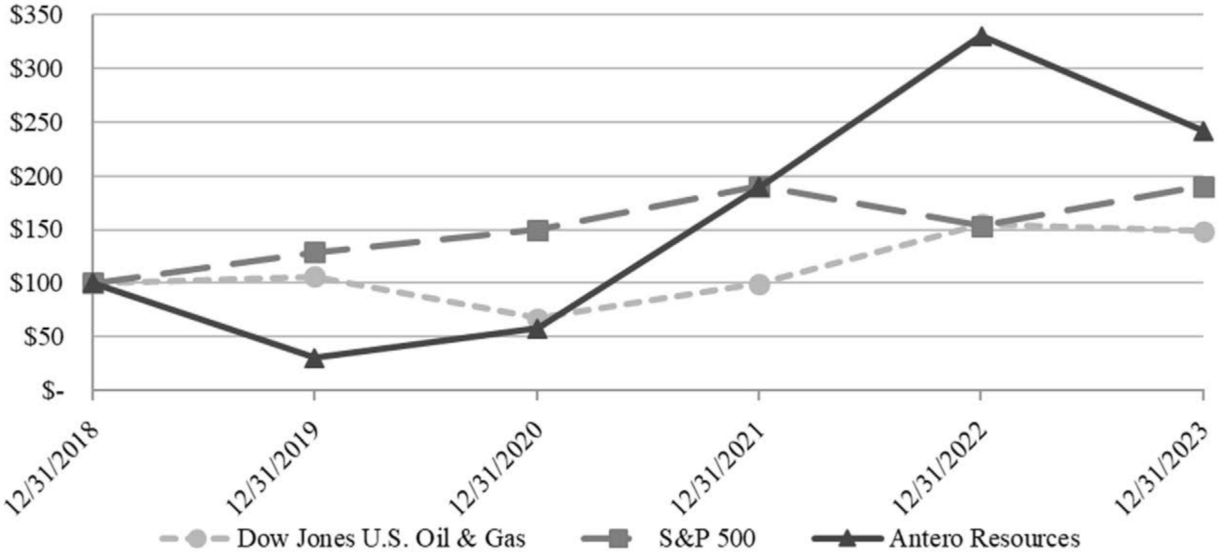
On February 15, 2022, our Board of Directors authorized a share repurchase program to opportunistically repurchase up to $1.0 billion of shares of our outstanding common stock. On October 25, 2022, our Board of Directors authorized a $1.0 billion increase to our share repurchase program to allow us to repurchase up to an aggregate of $2.0 billion of our outstanding common stock. Through December 31, 2023, we have repurchased 28 million shares of our common stock through our share repurchase program at a total cost of $949 million. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will be determined by us at our discretion and will depend on a variety of factors, including the market price of our common stock, general market and economic conditions and applicable legal requirements.

Dividend Restrictions

Our ability to pay dividends is governed by (i) the provisions of Delaware general corporation law, (ii) our Certificate of Incorporation and Bylaws, (iii) the indentures relating to our Senior Notes and 2026 Convertible Notes and (iv) the Credit Facility. We have not paid or declared any dividends on our common stock. The amount and timing of future payment of cash dividends on our common stock, if any, is within the discretion of the Board of Directors and will depend on our earnings, capital requirements, financial condition and other relevant factors. There is no assurance that we will pay any cash dividends on our common stock.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2018 in each of our common stock, the Standard & Poor's 500 ("S&P 500") Index, and the Dow Jones U.S. Oil & Gas Index. We believe the Dow Jones U.S. Oil & Gas Index is meaningful because it is an independent, objective view of the performance of similarly-sized energy companies.



The information in this Form 10-K appearing under the heading "Stock Performance Graph" is being "furnished" pursuant to Item 2.01(e) of Regulation S-K under the Securities Act and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act and shall not be deemed incorporated by reference into any filing under the Securities Act of the Exchange Act except to the extent that we specifically request that it be treated as such.

ITEM 6. RESERVED

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in natural gas, NGLs and oil prices, the timing of planned capital expenditures, our ability to fund our development programs, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, impacts of world health events and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Statement Regarding Forward-Looking Statements." Also, see the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors." We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Our Company

We are an independent oil and natural gas company engaged in the development, production, exploration and acquisition of natural gas, NGLs and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to develop our reserves and production, primarily on our existing multi-year inventory of drilling locations.

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Appalachian Basin. As of December 31, 2023, we held approximately 515,000 net acres in the Appalachian Basin. In addition, we estimate that approximately 172,000 net acres of our leasehold may be prospective for the slightly shallower Upper Devonian Shale.

As of December 31, 2023, our estimated proved reserves were 18.1 Tcfe, consisting of 10.6 Tcf of natural gas, 690 MMBbl of assumed recovered ethane, 532 MMBbl of C3+ NGLs and 29 MMBbl of oil. This represents a 2% increase in estimated proved reserves from December 31, 2022. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2023, we had 1,588 potential horizontal well locations on our existing leasehold acreage that were classified as proved, probable and possible.

We operate in the following reportable segments: (i) the exploration, development and production of natural gas, NGLs and oil; (ii) marketing of excess firm transportation capacity; and (iii) midstream services through our equity method investment in Antero Midstream Corporation ("Antero Midstream"). All of our operations are conducted in the United States.

Financing Highlights

Share Repurchase Program

During 2022, our Board of Directors authorized a share repurchase program that allows us to repurchase up to $2.0 billion of outstanding common stock. During the years ended December 31, 2022 and 2023, we repurchased 25 million and 3 million shares of our common stock, respectively, through our share repurchase program at a total cost of $874 million and $75 million, respectively. As of December 31, 2023, we have $1.1 billion remaining under our share repurchase program. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will be determined by us at our discretion and will depend on a variety of factors, including the market price of our common stock, general market and economic conditions and applicable legal requirements.

2026 Convertible Notes Conversions

During the year ended December 31, 2023, $9 million aggregate principal amount of the 2026 Convertible Notes were converted pursuant to their terms, and an additional $21 million aggregate principal amount of the 2026 Convertible Notes were induced into conversion by us. We elected to settle these conversions and inducements by issuing 7 million shares of common stock to the noteholders together with a cash inducement premium of $0.4 million. See Note 7—Long-Term Debt to the unaudited condensed consolidated financial statements for more information.

Drilling Partnership

On February 17, 2021, we announced the formation of a drilling partnership with QL, an affiliate of Quantum Energy Partners, for our 2021 through 2024 drilling program. Under the terms of the arrangement, each year in which QL participates represents an annual tranche, and QL will be conveyed a working interest in any wells spud by us during such tranche year. For 2021 through 2024, we agreed to the estimated IRR or our capital budget for each annual tranche, and QL agreed to participate in all four annual tranches. We develop and manage the drilling program associated with each tranche, including the selection of wells. Additionally, for each annual tranche, we will enter into assignments, bills of sale and conveyances pursuant to which QL will be conveyed a proportionate working interest percentage in each well spud in that year, which conveyances will not be subject to any reversion.

Under the terms of the arrangement, QL funded development capital of 20%, 15% and 15% for wells spud in 2021, 2022 and 2023, respectively, and will fund 20% of development capital for wells spud in 2024, which funding amounts represent QL's proportionate working interest in such wells. Additionally, we may receive a carry in the form of a one-time payment from QL for each annual tranche if the IRR for such tranche exceeds certain specified returns, which will be determined no earlier than October 31 and no later than December 1 following the end of each tranche year. We received a carry of $29 million for each of the 2021 and 2022 tranches during the years ended December 31, 2022 and 2023. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche will be for our account. Subject to the preceding sentence, for any wells included in a tranche, QL is obligated and responsible for its working interest share of costs and liabilities, and is entitled to its working interest share of revenues, associated with such wells for the life of such wells. See Note 3—Transactions to the consolidated financial statements for more information.

Market Conditions and Business Trends

Commodity Markets

Prices for natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Natural gas, NGLs and oil benchmark prices decreased significantly during 2023 as compared to 2022. As a result, we experienced a decrease in price realizations during the year ended December 31, 2023. We monitor the economic factors that impact natural gas, NGLs and oil prices, including domestic and foreign supply and demand indicators, domestic and foreign commodity inventories, the actions of Organization of Petroleum Exporting Countries and other large producing nations and the current conflicts in Ukraine and in the Middle East, among others. In the current economic environment, we expect that commodity prices for some or all of the commodities we produce could remain volatile. This volatility is beyond our control and may adversely impact our business, financial condition, results of operations and future cash flows.

The following table details the average benchmark natural gas and oil prices:

	Year Ended December 31,	
	2022	2023
Henry Hub (1) ($/Mcf)	$ 6.64	2.74
West Texas Intermediate (2) ($/Bbl)	94.23	77.62

(1) New York Mercantile Exchange first of month average natural gas price.
(2) Energy Information Administration calendar month average settled futures price.

Hedge Position

Antero Resources (Excluding Martica)

We are exposed to certain commodity price risks relating to our ongoing business operations, and we use derivative instruments when circumstances warrant to manage such risks. In addition, we periodically enter into contracts that contain embedded features that are required to be bifurcated and accounted for separately as derivatives. Due to our improved liquidity and leverage position as compared to historical levels, the percentage of our expected production that we hedge has decreased. For the years ended December 31, 2022 and 2023, 33% and 1%, respectively, of our production was hedged through fixed price commodity swaps, and as of December 31, 2023, we had no fixed price commodity swap positions. The tables and narrative below exclude derivative instruments attributable to Martica, our consolidated VIE, since all gains or losses from such contracts are fully attributable to the noncontrolling interests in Martica.

As of December 31, 2023, our natural gas basis swap positions settle on the pricing index to basis differential of the Columbia Gas Transmission pipeline ("TCO") to the NYMEX Henry Hub natural gas price were as follows:

Commodity / Settlement Period	Index to Basis Differential	Contracted Volume	Weighted Average Hedged Differential
Natural Gas			
January-December 2024	NYMEX to TCO	18 Bcf	0.530 /MMBtu

We have a call option and an embedded put option tied to NYMEX pricing for the production volumes associated with the Company's retained interest in the VPP properties. As of December 31, 2023, our call option and embedded put option arrangements were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Call Option Strike Price	Embedded Put Option Strike Price
Natural Gas				
January-December 2024	Henry Hub	19 Bcf	2.477 /MMBtu	2.527 /MMBtu
January-December 2025	Henry Hub	16 Bcf	2.564 /MMBtu	2.614 /MMBtu
January-December 2026	Henry Hub	12 Bcf	2.629 /MMBtu	2.679 /MMBtu
		47 Bcf	2.544 /MMBtu	2.594 /MMBtu

As of December 31, 2023, the estimated fair value of our commodity derivative contracts, excluding Martica, was a net liability of $32 million. See Note 11—Derivative Instruments to the consolidated financial statements for more information.

Martica

Our consolidated VIE, Martica, also maintains a portfolio of fixed swap natural gas, NGLs and oil derivatives for the benefit of the noncontrolling interests in Martica. As such, all gains and losses attributable to Martica's derivative portfolio are fully attributable to the noncontrolling interests in Martica. As of December 31, 2023, Martica's fixed price natural gas, NGLs and oil swap positions were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Weighted Average Price
Natural Gas			
January-December 2024	Henry Hub	9 Bcf	2.33 /MMBtu
January-March 2025	Henry Hub	1 Bcf	2.53 /MMBtu
		10 Bcf	2.36 /MMBtu
Oil			
January-December 2024	West Texas Intermediate	16 MBbl	44.02 /Bbl
January-March 2025	West Texas Intermediate	3 MBbl	45.06 /Bbl
		19 MBbl	44.21 /Bbl

As of December 31, 2023, the estimated fair value of Martica's commodity derivative contracts was a net liability of $5 million. See Note 11—Derivative Instruments to the consolidated financial statements for more information.

Economic Indicators

The economy experienced elevated inflation levels as a result of global supply and demand imbalances, where global demand outpaced supplies beginning in 2021 and continuing through 2023. For example, CPI for all urban consumers increased 8% from December 2021 to December 2022 and an additional 4% from December 2022 to December 2023 as compared to the Federal Reserve's stated goal of 2%. In order to manage the inflation risk present in the United States' economy, the Federal Reserve utilized monetary policy in the form of interest rate increases beginning in March 2022 in an effort to bring the inflation rate in line with its stated goal of 2% on a long-term basis. Between March 2022 and December 2023, the Federal Reserve increased the federal funds interest rate by 5.25%. While inflationary pressures in the United States' economy have begun to subside, we continue to be impacted by the increased federal funds interest rate. See "—Results of Operations" for more information.

The economy also continues to be impacted by the effects of global events. These events have often caused global supply chain disruptions with additional pressure due to trade sanctions on Russia and other global trade restrictions, among others. However, our supply chain has not experienced any significant interruptions as a result of such events.

Inflationary pressures, particularly as they relate to certain of our long-term contracts with CPI-based adjustments, and supply chain disruptions have and could continue to result in increases to our operating and capital costs that are not fixed. These economic variables are beyond our control and may adversely impact our business, financial condition, results of operations and future cash flows.

Sources of Our Revenues

- *Natural gas, NGLs and oil sale revenues.* Our revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our production is entirely from within the continental United States; however, some of our production revenues are attributable to customers who export our products. During 2022 and 2023, our production revenues were comprised of 67% and 51%, respectively, from the sale of natural gas and 33% and 49%, respectively, from the sale of NGLs and oil. Natural gas, NGLs and oil prices are inherently volatile and are influenced by many factors outside of our control. All of our production is derived from natural gas wells, some of which also produce NGLs which are extracted through processing, and oil.

- *Commodity derivatives.* We utilize derivative instruments to hedge future sales prices for a portion of our production when circumstances warrant. We currently utilize call and embedded put options, as well as basis swap contracts that hedge the difference between the NYMEX index price and a local index price. We may also enter into commodity fixed price swaps, collars or other similar instruments related to the price risk associated with our production. Due to our improved liquidity and leverage position as compared to historical levels, the percentage of our expected production that we hedge has decreased. As of December 31, 2023, we had no fixed price commodity swap positions. See Note 11—Derivative Instruments to the consolidated financial statements for more information. At the end of each accounting period, we estimate the fair value of these derivative instruments, because we have not elected hedge accounting, we recognize changes in the fair value of these derivative instruments in earnings. We expect continued volatility in the prices we receive for our production and the fair value of our derivative instruments.

- *Marketing revenues.* Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties.

- *Gathering, compression and water handling revenues.* Gathering, compression and water handling revenues are derived from our ownership interest in Antero Midstream.

Principal Components of Our Cost Structure

- *Lease operating expenses.* These are the operating costs incurred to maintain our production. Such costs include produced water hauling, water handling, water disposal, and labor-related costs to monitor producing wells, maintenance, repairs and workover expenses. Cost levels for these expenses can vary based on the volume of water produced, supply and demand for oilfield services, activity levels, and other factors.

- *Gathering, compression, processing and transportation.* These costs include the fees paid to Antero Midstream and other third parties who operate low and high pressure gathering and compression systems that transport our gas. They also include costs to process and extract NGLs from our liquids-rich gas and to transport our natural gas, NGLs and oil to market. We often enter into fixed price long-term contracts that secure transportation and processing capacity, which may include minimum volume commitments, the cost for which is included in these expenses to the extent that they are not associated with excess capacity. Costs associated with excess capacity are included in marketing expenses.

- *Water handling.* Water handling expenses relate to the direct operating costs attributable to fresh water and other fluid handling services.

- *Production and ad valorem taxes.* Production and ad valorem taxes consist of severance and ad valorem taxes. Severance taxes are paid on produced natural gas and oil based on a percentage of sales prices, which exclude the effects of our derivative instruments, or at fixed per-unit rates established by state authorities. Ad valorem taxes are paid based on the value of our reserves as well as the value of property and equipment.

- *Marketing expenses*. We purchase and sell third-party natural gas and NGLs and market our excess capacity under long-term contracts. Marketing costs include the cost of purchased third-party natural gas and NGLs. We also classify firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize this excess capacity as marketing expenses, because we market this excess capacity to third parties. We enter into long-term firm transportation agreements for a significant portion of our current and expected future production in order to secure capacity on major pipelines.

- *Exploration and mine expenses.* These are primarily costs related to unsuccessful leasing efforts, as well as geological and geophysical costs, including seismic costs, costs of unsuccessful exploratory dry holes and costs of other exploratory activities, including costs associated with our sand mine.

- *Impairment of property and equipment.* These costs include impairment and costs associated with leases expirations, impairment of design and initial costs related to pads that are no longer planned to be placed into service and impairment of proved properties due to lower future commodity prices. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks and future plans to develop the acreage. We record impairment charges for proved properties on a geological reservoir basis when events or changes in circumstances indicate that a property's carrying amount may not be recoverable. We also record impairment charges for other property and equipment when events or changes in circumstances indicate that the carrying amount of such property and/or equipment may not be recoverable.

- *Depletion, depreciation and amortization.* DD&A includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts and allocate these costs using the units of production method. Depreciation is computed over an asset's estimated useful life using the straight-line basis.

- *General and administrative expense.* These costs include overhead, including payroll and benefits for our staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other professional fees, insurance, legal expenses and other administrative expenses. General and administrative expense also includes noncash equity-based compensation expense. See Note 9—Equity-Based Compensation to the consolidated financial statements for more information.

- *Interest expense.* We finance a portion of our capital expenditures, working capital requirements and acquisitions with borrowings under our Credit Facility, which has a variable rate of interest based on SOFR (defined below in "—Capital Resources and Liquidity—Debt Agreements—Credit Facility") or the Alternate Base Rate (each term as defined in the Credit Facility). As of December 31, 2023, we had an outstanding balance on the Credit Facility of $417 million with a weighted average interest rate of 7.71%. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. As of December 31, 2023, we had fixed interest rates ranging from 5.375% to 8.375% on our Senior Notes with an aggregate principal balance of $1.1 billion and 4.25% on our 2026 Convertible Notes with an aggregate principal balance of $26 million. See Note 7—Long-Term Debt to the consolidated financial statements for more information.

- *Income tax expense.* We are subject to state and U.S. federal income taxes, but we are currently not in a cash tax paying position with respect to U.S. federal income taxes. The difference between our financial statement income tax expense and our current U.S. federal income tax liability is primarily due to the differences in the tax and financial statement treatment of oil and gas properties, the effects of noncontrolling interests and the deferral of unsettled commodity derivative gains and losses for tax purposes until they are settled. We have recorded deferred income tax expense to the extent our deferred income tax liabilities exceed our deferred income tax assets. See Note 13—Income Taxes to the consolidated financial statements for more information.

Results of Operations

We have three operating segments: (i) the exploration, development and production of natural gas, NGLs and oil; (ii) marketing and utilization of excess firm transportation capacity; and (iii) midstream services through our equity method investment in Antero Midstream. Revenues from Antero Midstream's operations were primarily derived from intersegment transactions for services provided to our exploration and production operations by Antero Midstream. All intersegment transactions were eliminated upon consolidation, including revenues from water handling services provided by Antero Midstream, which we capitalized as proved property development costs. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and NGLs and to market and utilize excess firm transportation capacity. See Note 17—Reportable Segments to the consolidated financial statements for more information.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2023

The operating results of our reportable segments were as follows (in thousands):

	Year Ended December 31, 2022				
	Exploration and Production	**Marketing**	**Equity Method Investment in Antero Midstream**	**Elimination of Unconsolidated Affiliate**	**Consolidated Total**
Revenue and other:					
Natural gas sales	$ 5,520,419	—	—	—	5,520,419
Natural gas liquids sales	2,498,657	—	—	—	2,498,657
Oil sales	275,673	—	—	—	275,673
Commodity derivative fair value losses	(1,615,836)	—	—	—	(1,615,836)
Gathering, compression and water handling	—	—	919,985	(919,985)	—
Marketing	—	416,758	—	—	416,758
Amortization of deferred revenue, VPP	37,603	—	—	—	37,603
Other revenue and income	5,162	—	—	—	5,162
Total revenue	6,721,678	416,758	919,985	(919,985)	7,138,436
Operating expenses:					
Lease operating	99,595	—	—	—	99,595
Gathering and compression	892,533	—	75,889	(75,889)	892,533
Processing	869,744	—	—	—	869,744
Transportation	843,103	—	—	—	843,103
Water handling	—	—	104,365	(104,365)	—
Production and ad valorem taxes	287,406	—	—	—	287,406
Marketing	—	531,304	—	—	531,304
Exploration and mine expenses	7,409	—	—	—	7,409
General and administrative (excluding equity-based compensation)	137,466	—	42,471	(42,471)	137,466
Equity-based compensation	35,443	—	19,654	(19,654)	35,443
Depletion, depreciation and amortization	680,600	—	131,762	(131,762)	680,600
Impairment of property and equipment	149,731	—	3,702	(3,702)	149,731
Accretion of asset retirement obligations	4,627	—	222	(222)	4,627
Contract termination, loss contingency and other operating expenses	25,099	—	4,705	(4,705)	25,099
Loss (gain) on sale of assets	471	—	(2,251)	2,251	471
Total operating expenses	4,033,227	531,304	380,519	(380,519)	4,564,531
Operating income (loss)	$ 2,688,451	(114,546)	539,466	(539,466)	2,573,905
Equity in earnings of unconsolidated affiliates	$ 72,327	—	94,218	(94,218)	72,327

	Year Ended December 31, 2023				
	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream	Elimination of Unconsolidated Affiliate	Consolidated Total
Revenue and other:					
Natural gas sales	$ 2,192,349	—	—	—	2,192,349
Natural gas liquids sales	1,836,950	—	—	—	1,836,950
Oil sales	247,146	—	—	—	247,146
Commodity derivative fair value gains	166,324	—	—	—	166,324
Gathering, compression and water handling	—	—	1,041,771	(1,041,771)	—
Marketing	—	206,122	—	—	206,122
Amortization of deferred revenue, VPP	30,552	—	—	—	30,552
Other revenue and income	2,529	—	—	—	2,529
Total revenue	4,475,850	206,122	1,041,771	(1,041,771)	4,681,972
Operating expenses:					
Lease operating	118,441	—	—	—	118,441
Gathering and compression	858,462	—	95,507	(95,507)	858,462
Processing	1,014,181	—	—	—	1,014,181
Transportation	769,715	—	—	—	769,715
Water handling	—	—	117,658	(117,658)	—
Production and ad valorem taxes	158,855	—	—	—	158,855
Marketing	—	284,965	—	—	284,965
Exploration and mine expenses	2,700	—	—	—	2,700
General and administrative (excluding equity-based compensation)	164,997	—	39,462	(39,462)	164,997
Equity-based compensation	59,519	—	31,606	(31,606)	59,519
Depletion, depreciation and amortization	689,966	—	136,059	(136,059)	689,966
Impairment of property and equipment	51,302	—	146	(146)	51,302
Accretion of asset retirement obligations	3,244	—	177	(177)	3,244
Loss (gain) on sale of assets	(447)	—	6,030	(6,030)	(447)
Contract termination, loss contingency and other operating expenses	29,179	23,763	3,264	(3,264)	52,942
Total operating expenses	3,920,114	308,728	429,909	(429,909)	4,228,842
Operating income (loss)	$ 555,736	(102,606)	611,862	(611,862)	453,130
Equity in earnings of unconsolidated affiliates	$ 82,952	—	105,456	(105,456)	82,952

Exploration and Production Segment

The following table sets forth selected operating data of the exploration and production segment:

	Year Ended December 31, 2022	Year Ended December 31, 2023	Amount of Increase (Decrease)	Percent Change
Production data [1] [2]:				
Natural gas (Bcf)	798	815	17	2 %
C2 Ethane (MBbl)	18,818	24,657	5,839	31 %
C3+ NGLs (MBbl)	39,914	41,927	2,013	5 %
Oil (MBbl)	3,223	3,874	651	20 %
Combined (Bcfe)	1,170	1,238	68	6 %
Daily combined production (MMcfe/d)	3,204	3,392	188	6 %
Average prices before effects of derivative settlements [3]:				
Natural gas (per Mcf)	$ 6.92	2.69	(4.23)	(61)%
C2 Ethane (per Bbl) [4]	$ 20.41	10.14	(10.27)	(50)%
C3+ NGLs (per Bbl)	$ 52.98	37.85	(15.13)	(29)%
Oil (per Bbl)	$ 85.53	63.80	(21.73)	(25)%
Weighted Average Combined (per Mcfe)	$ 7.09	3.45	(3.64)	(51)%
Average realized prices after effects of derivative settlements [3]:				
Natural gas (per Mcf)	$ 4.54	2.66	(1.88)	(41)%
C2 Ethane (per Bbl) [4]	$ 20.38	10.14	(10.24)	(50)%
C3+ NGLs (per Bbl)	$ 52.63	37.80	(14.83)	(28)%
Oil (per Bbl)	$ 84.88	63.50	(21.38)	(25)%
Weighted Average Combined (per Mcfe)	$ 5.46	3.43	(2.03)	(37)%
Average costs (per Mcfe):				
Lease operating	$ 0.09	0.10	0.01	11 %
Gathering and compression	$ 0.76	0.69	(0.07)	(9)%
Processing	$ 0.74	0.82	0.08	11 %
Transportation	$ 0.72	0.62	(0.10)	(14)%
Production and ad valorem taxes	$ 0.25	0.13	(0.12)	(48)%
Marketing expense, net	$ 0.10	0.06	(0.04)	(40)%
General and administrative (excluding equity-based compensation)	$ 0.12	0.13	0.01	8 %
Depletion, depreciation, amortization and accretion	$ 0.59	0.56	(0.03)	(5)%

(1) Production data excludes volumes related to the VPP.

(2) Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and may not reflect their relative economic value.

(3) Average prices reflect the before and after effects of our settled commodity derivatives. Our calculation of such after effects includes gains (losses) on settlements of commodity derivatives (but does not include proceeds from the derivative monetizations in 2023), which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes.

(4) The average realized price for the years ended December 31, 2022 and 2023 includes $10 million and $15 million, respectively, of proceeds related to a take-or-pay contract. Excluding the effect of these proceeds, the average realized price for ethane before and after the effects of derivatives for the years ended December 31, 2022 and 2023 would have been $19.88 per Bbl and $9.55 per Bbl, respectively.

Natural gas sales. Revenues from sales of natural gas decreased from $5.5 billion, for the year ended December 31, 2022 to $2.2 billion for the year ended December 31, 2023, a decrease of $3.3 billion, or 60%. Lower commodity prices (excluding the effects of derivative settlements) during the year ended December 31, 2023 accounted for an approximate $3.4 billion decrease in year-over-year natural gas sales revenue (calculated as the change in the year-to-year average price excluding the net proceeds from the litigation times current year production volumes). Higher natural gas production volumes accounted for an approximate $121 million increase in year-over-year natural gas sales revenue (calculated as the change in year-to-year volumes times the prior year average price).

NGLs sales. Revenues from sales of NGLs decreased from $2.5 billion for the year ended December 31, 2022 to $1.8 billion for the year ended December 31, 2023, a decrease of $0.7 million, or 26%. Lower commodity prices (excluding the effects of derivative settlements) during the year ended December 31, 2023 accounted for an approximate $888 million decrease in year-over-year revenues (calculated as the change in the year-to-year average price times current year production volumes). Higher NGLs production volumes during the year ended December 31, 2023 accounted for an approximate $226 million increase in year-over-year NGLs revenues (calculated as the change in year-to-year volumes times the prior year average price).

Oil sales. Revenues from sale of oil decreased from $276 million for the year ended December 31, 2022 to $247 million for the year ended December 31, 2023, a decrease of $29 million, or 10%. Lower oil prices for the year ended December 31, 2023 excluding the effects of derivative settlements) accounted for an approximate $84 million decrease in year-over-year oil revenues (calculated as the change in the year-to-year average price times current year production volumes). Higher oil production volumes during the year ended December 31, 2023 accounted for an approximate $55 million increase in year-over-year oil revenues (calculated as the change in year-to-year volumes times the prior year average price).

Commodity derivative fair value losses. Our commodity derivatives included fixed price swap contracts, swaptions, basis swap contracts, call options and embedded put options. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment. Consequently, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations and comprehensive income (loss). For the years ended December 31, 2022 and 2023, our commodity hedges resulted in derivative fair value losses of $1.6 billion and fair value gains of $166 million, respectively. For the year ended December 31, 2022, commodity derivative fair value losses included $1.9 billion of net cash payments for settled derivative losses. For the year ended December 31, 2023, commodity derivative fair value gains included $25 million of net cash payments for settled commodity derivative losses, as well as $202 million for payments on derivatives that were settled prior to their contractual settlement dates.

Commodity derivative fair value gains or losses vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled or monetized or terminated prior to settlement. Derivative asset or liability positions at the end of any accounting period may reverse to the extent future commodity prices increase or decrease from their levels at the end of the accounting period, or as gains or losses are realized through settlement. Additionally, substantially all of our production is currently unhedged for 2024 and beyond, which limits our exposure to volatility in the fair value of our derivative instruments related to commodity price changes in the future.

Amortization of deferred revenue, VPP. Amortization of deferred revenues associated with the VPP decreased from $38 million for the year ended December 31, 2022 to $31 million for the year ended December 31, 2023, a decrease of $7 million or 19%, primarily due to lower production volumes attributable to the VPP properties between periods. Amortization of the deferred revenues associated with the VPP are recognized as the production volumes are delivered at $1.61 per MMBtu over the contractual term.

Lease operating expense. Lease operating expense increased from $100 million, or $0.09 per Mcfe, for the year ended December 31, 2022 to $118 million, or $0.10 per Mcfe, for the year ended December 31, 2023, an increase of $18 million or $0.01 per Mcfe, primarily due to higher oilfield service, workover and produced water handling costs.

Gathering, compression, processing and transportation expense. Gathering, compression, processing and transportation expense remained consistent at $2.6 billion for each of the years ended December 31, 2022 and 2023. This was primarily a result of the following:

- Gathering and compression costs on a per unit basis decreased from $0.76 per Mcfe for the year ended December 31, 2022 to $0.69 per Mcfe for the year ended December 31, 2023, primarily due to lower fuel costs as a result of decreased commodity prices, partially offset by annual CPI-based based adjustments between periods.

- Processing costs on a per unit basis increased from $0.74 per Mcfe for the year ended December 31, 2022 to $0.82 per Mcfe for the year ended December 31, 2023, primarily due to increased costs for NGLs processing and transportation, which include annual CPI-based and commodity based adjustments, as well as higher terminal fees and ethane transportation.

- Transportation costs on a per unit basis decreased from $0.72 per Mcfe for the year ended December 31, 2022 to $0.62 per Mcfe and for the year ended December 31, 2023, primarily due to lower fuel costs as a result of lower commodity prices between periods.

Production and ad valorem tax expense. Production and ad valorem taxes decreased from $287 million for the year ended December 31, 2022 to $159 million for the year ended December 31, 2023, a decrease of $128 million or 45%, primarily due to lower commodity prices between periods, partially offset by higher production volumes between periods. Production and ad valorem taxes as a percentage of natural gas revenues increased from 5% for the year ended December 31, 2022 to 7% for the year ended December 31, 2023.

General and administrative expense. General and administrative expense (excluding equity-based compensation expense) increased from $137 million for the year ended December 31, 2022 to $165 million for the year ended December 31, 2023, an increase of $28 million or 20%, primarily due to higher salary and wage expense, professional service fees, office operating costs and software license costs between periods. We had 586 and 604 employees as of December 31, 2022 and 2023, respectively. General and administrative expense on a per unit basis (excluding equity-based compensation) increased from $0.12 per Mcfe for the year ended December 31, 2022 to $0.13 per Mcfe for the year ended December 31, 2023 as a result of our higher overall general and administrative costs, partially offset by increased production volumes between periods.

Equity-based compensation expense. Noncash equity-based compensation expense increased from $35 million for the year ended December 31, 2022 to $60 million for the year ended December 31, 2023, an increase of $25 million or 68%, primarily due to an increase in the annual equity awards granted during 2022 and 2023 as compared to prior years, which were temporarily and significantly reduced during 2020 and supplemented by our cash awards program. Our equity awards vest over three or four year service periods, and our equity incentive program began returning to normal levels in 2021. See Note 9—Equity-Based Compensation to the consolidated financial statements for more information.

Depletion, depreciation and amortization expense. DD&A expense increased from $681 million, or $0.59 per Mcfe for the year ended December 31, 2022 to $690 million, or $0.56 per Mcfe for the year ended December 31, 2023, an increase of $9 million. The decrease in DD&A expense per Mcfe between periods was primarily due to higher reserve volumes during the year ended December 31, 2023.

Impairment of property and equipment. Impairment of property and equipment decreased from $150 million for the year ended December 31, 2022 to $51 million for the year ended December 31, 2023, a decrease of $99 million, or 66%, primarily related to lower impairments of expiring leases between periods and the impairment of our sand mine of $48 million during the year ended December 31, 2022. During both periods, we recognized impairments primarily related to expiring leases as well as design and initial costs related to pads we no longer plan to place into service.

Contract termination, loss contingency and other operating expenses. Contract termination, loss contingency and other operating expenses attributable to our exploration and production segment of $25 million for the year ended December 31, 2022 were primarily due to a payment for the cancellation of the Smithburg 2 gas processing plant and the cancellation of a gas gathering agreement. Contract termination, loss contingency and other operating expenses attributable to our exploration and production segment of $29 million for the year ended December 31, 2023 were primarily due to a loss contingency and the early termination of certain drilling and completion contracts.

Marketing Segment

Where feasible, we purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity, or engage third parties to conduct these activities on our behalf, in order to optimize the revenues from these transportation agreements. We have entered into long-term firm transportation agreements for a significant portion of our current and expected future production in order to secure guaranteed capacity to favorable markets.

Net marketing expense decreased from $115 million, or $0.10 per Mcfe, for the year ended December 31, 2022 to $79 million, or $0.06 per Mcfe, for the year ended December 31, 2023, primarily due to lower firm transportation commitments, partially offset by lower marketing margin on third-party product purchases between periods.

Marketing revenue. Marketing revenue decreased from $417 million for the year ended December 31, 2022 to $206 million for the year ended December 31, 2023, a decrease of $211 million, or 51%. This fluctuation primarily resulted from the following:

- Natural gas marketing revenue decreased by $187 million between periods primarily due to lower natural gas prices and marketing volumes. Lower natural gas prices accounted for an approximate $182 million decrease in year-over-year marketing revenues (calculated as the change in the year-to-year average price times current year marketing volumes), and lower natural gas marketing volumes accounted for a $5 million decrease in year-over-year marketing revenues (calculated as the change in year-to-year volumes times the prior year average price).

- Ethane marketing revenues were $42 million for the year ended December 31, 2022. There were no third-party ethane marketing revenues for the year ended December 31, 2023.

- Oil marketing revenue increased by $16 million between periods primarily due to higher marketing volumes, partially offset by lower oil prices. Higher oil marketing volumes accounted for a $42 million increase in year-over-year marketing revenues (calculated as the change in year-to-year volumes times the prior year average price), and lower oil prices accounted for an approximate $26 million decrease in year-over-year marketing revenues (calculated as the change in the year-to-year average price times current year marketing volumes).

Marketing expense. Marketing expense decreased from $531 million for the year ended December 31, 2022 to $285 million for the year ended December 31, 2023, a decrease of $246 million, or 46%. Marketing expense includes the cost of third-party purchased natural gas, NGLs and oil as well as firm transportation costs, including costs related to current excess firm capacity. The cost of third-party natural gas and NGLs decreased $188 million and $28 million, respectively, between periods, partially offset by increased oil purchases of $14 million between periods. The total costs decreased between periods primarily due to lower commodity prices and lower natural gas and NGL third-party marketing volumes, partially offset by increased oil marketing volumes. Firm transportation costs were $149 million for the year ended December 31, 2022 and $105 million for the year ended December 31, 2023, a decrease of $44 million primarily due to the reduction in firm transportation commitments between periods.

Contract termination, loss contingency and other operating expenses. Our marketing segment did not incur any contract termination, loss contingency and other operating expenses for the year ended December 31, 2022. Contract termination, loss contingency and other operating expenses attributable to our marketing segment for the year ended December 31, 2023 relate to a $24 million payment for the early termination of our firm transportation commitment of 200,000 MMBtu/d on the Equitrans pipeline.

Antero Midstream Segment

Antero Midstream revenue. Revenue from the Antero Midstream segment increased from $0.9 billion for the year ended December 31, 2022 to $1.0 billion for the year ended December 31, 2023, an increase of $0.1 billion, or 13%, primarily due to increased throughput and higher water handling volumes between periods, as well as higher low pressure, compression, high pressure and fresh water delivery fees as a result of an annual CPI-based adjustments and increased other fluid handling fees primarily due to increased costs partially due to inflationary pressures between periods that impact the cost plus 3% and cost of service rates.

Antero Midstream operating expense. Total operating expense related to the Antero Midstream segment increased from $381 million for the year ended December 31, 2022 to $430 million for the year ended December 31, 2023, an increase of $49 million, or 13%, primarily due to increased direct operating costs, equity-based compensation and depreciation expense, partially offset by decreased general and administrative expenses (excluding equity-based compensation expense) between periods. Direct operating expenses increased between periods primarily due to 12 compressors that were acquired during the fourth quarter of 2022, higher wastewater trucking rates, increased heavy maintenance expense and an increased number of locations connected to its water blending system between periods. Equity-based compensation increased between periods primarily due to an increase in the annual equity awards granted during the years ended December 31, 2022 and 2023 as compared to prior years, which were temporarily and significantly reduced during 2020 and supplemented by our cash awards program. Antero Midstream's equity awards vest over three or four year service periods, and its equity incentive program began returning to normal levels in 2021. Depreciation expense increased between periods primarily due to assets acquired during the fourth quarter of 2022 and assets placed in service during the year ended December 31, 2023, partially offset by lower depreciation expense associated with Antero Midstream's program to repurpose underutilized compressor units to expand existing or construct new compressor stations between periods. General and administrative expenses (excluding equity-based compensation expense) decreased between periods primarily due to lower legal costs.

Items Not Allocated to Segments

Interest expense. Interest expense decreased from $125 million for the year ended December 31, 2022 to $118 million for the year ended December 31, 2023, a decrease of $7 million, or 6%, primarily due to our redemption or repurchase of $990 million in aggregate principal amount of certain of our Senior Notes during the year ended December 31, 2022, partially offset by higher benchmark interest rates during the year ended December 31, 2023 and higher average Credit Facility borrowings between periods. See Note 7—Long-Term Debt to the consolidated financial statements for more information.

Loss on early extinguishment of debt. During the year ended December 31, 2022, we redeemed or repurchased through our previously disclosed tender offer and open market transactions (i) the remaining $585 million aggregate principal amount of our 2025 Notes at a redemption price of 101.25% of the principal amount thereof, plus accrued and unpaid interest, (ii) $228 million of our 2026 Notes at a weighted average redemption price of 109% of the principal amount thereof, plus accrued and unpaid interest and (iii) $177 million of our 2029 Notes at a weighted average redemption price of 106% of the principal amount thereof, plus accrued and unpaid interest. For such redemptions and repurchases, we recognized a $46 million loss on early extinguishment of debt. There were no redemptions or repurchases of our Senior Notes during the year ended December 31, 2023. See Note 7—Long-Term Debt to the consolidated financial statements for more information.

Income tax expense. Income tax expense decreased from $449 million for the year ended December 31, 2022 to $76 million for the year ended December 31, 2023 primarily due to lower pre-tax income between periods. The effective tax rate for the years ended December 31, 2022 and 2023 were 18.1% and 18.2%, respectively. Our effective tax rate was different than the statutory rate of 21% primarily due to the effects of state income taxes, the dividends received deduction, equity-based compensation expenses, noncontrolling interests, the effects of a West Virginia apportionment tax law change enacted in 2021 and changes in Pennsylvania's corporate income tax rate. See Note 13—Income Taxes to our consolidated financial statements more for information.

As of December 31, 2023, we had U.S. federal and state NOL carryforwards of $1.0 billion and $1.9 billion, respectively. Many of these NOL carryforwards expire at various dates between 2025 and 2041 while others have no expiration date. Potential future legislation or the imposition of new or increased taxes may have a significant effect on our future taxable position. The impact of any such change would be recorded in the period in which such interpretation is received or legislation is enacted.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2022

Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2022 for a discussion of the results of operations for the year ended December 31, 2021 compared to the year ended December 31, 2022.

Capital Resources and Liquidity

Overview

Our primary sources of liquidity have been through net cash provided by operating activities, borrowings under our Credit Facility, issuances of debt and equity securities and additional contributions from our asset sales, including our drilling partnership. Our primary use of cash has been for the exploration, development and acquisition of oil and natural gas properties. As we develop our reserves, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in developing our proved reserves and production will be highly dependent on net cash provided by operating activities and the capital resources available to us.

The Credit Facility has a borrowing base of $3.5 billion and current lender commitments of $1.6 billion. The borrowing base is redetermined semi-annually based on certain factors including our reserves, natural gas, NGLs and oil commodity prices, and the value of our hedge portfolio. The next redetermination of the borrowing base is scheduled to occur in April 2024. For a discussion of the risks of a decrease in the borrowing base under the Credit Facility, see "Item 1A. Risk Factors—The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility."

Our commodity hedge position provides us with liquidity for a portion of our production because it provides us with the relative certainty of receiving a portion of our future expected revenues from operations despite potential declines in the price of natural gas. Due to our improved liquidity and leverage position as compared to historical levels, the percentage of our expected production that we hedge has decreased. For the years ended December 31, 2022 and 2023, 33% and 1%, respectively, of our production was hedged through fixed price commodity swaps, and as of December 31, 2023, we had no fixed price commodity swap positions. Our ability to make significant acquisitions for cash would require us to utilize borrowings on the Credit Facility or obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. The Credit Facility is funded by a syndicate of 16 banks. We believe that the participants in the syndicate have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of the Credit Facility.

2023 Capital Spending and 2024 Capital Budget

For the year ended December 31, 2023, our total consolidated capital expenditures were $1.1 billion, including drilling and completion expenditures of $909 million, leasehold additions of $148 million and other capital expenditures of $15 million. We completed 70 net horizontal wells during the year ended December 31, 2023. Our net capital budget for 2024 is $725 million to $800 million. Our budget includes: a range of $650 million to $700 million for drilling and completion and $75 million to $100 million for leasehold expenditures. We do not budget for acquisitions. During 2024, we plan to complete 45 to 50 net horizontal wells in the Appalachian Basin. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities and commodity prices.

Our capital budget may be adjusted as business conditions warrant as the amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs and oil prices decline, or costs increase, to levels that do not generate an acceptable level of corporate returns, we may defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity, and to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows.

Based on strip prices as of December 31, 2023, we believe that net cash provided from operating activities and available borrowings under the Credit Facility will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "—Debt Agreements."

See Note 14—Commitments to the consolidated financial statements for information on our off-balance sheet arrangements.

Cash Flows

The following table summarizes our cash flows (in thousands):

	Year Ended December 31,	
	2022	2023
Net cash provided by operating activities	$ 3,051,342	994,721
Net cash used in investing activities	(943,612)	(1,140,767)
Net cash provided by (used in) financing activities	(2,107,730)	146,046
Net increase in cash and cash equivalents	$ —	—

Year Ended December 31, 2022 Compared to Year Ended December 31, 2023

Operating activities. Net cash provided by operating activities was $3.1 billion and $1.0 billion for the years ended December 31, 2022 and 2023, respectively. Net cash provided by operating activities decreased primarily due to decreases in commodity prices, a $202 million payment for early settlement of our swaption agreement and higher contract termination, gathering, compression, processing and transportation, general and administrative (excluding equity-based compensation expense) and lease operating expenses. These operating cash flow decreases were partially offset by higher production, lower production and ad valorem taxes, interest expense and net marketing expense, decreased payments for commodity derivative settlements and changes in working capital between periods.

Our net operating cash flows are sensitive to many variables, the most significant of which is the volatility of natural gas, NGLs and oil prices, as well as volatility in the cash flows attributable to settlement of our commodity derivatives. Prices for natural gas, NGLs and oil are primarily determined by prevailing market conditions. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets, storage capacity and other variables influence the market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Investing activities. Net cash used in investing activities increased from $0.9 billion for the year ended December 31, 2022 to $1.1 billion for the year ended December 31, 2023, primarily due to increased drilling and completions activity and land purchases, as well as higher drilling and water costs between periods.

Financing activities. Net cash flows used in financing activities was $2.1 billion for the year ended December 31, 2022. Net cash flows provided by financing activities was $0.1 billion for the year ended December 31, 2023. This increase between periods is primarily due to lower Senior Note redemptions and repurchases of $1.0 billion, decreased share repurchases of $0.8 billion and higher net borrowings on our Credit Facility of $0.3 billion.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2022

Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity" in our Annual Report on Form 10-K for the year ended December 31, 2022 for a discussion of the cash flows for the year ended December 31, 2021 compared to the year ended December 31, 2022.

Debt Agreements

Credit Facility

We have a senior secured revolving credit facility with a consortium of bank lenders. On October 26, 2021, we entered into an amended and restated senior secured revolving credit facility, the Credit Facility. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our assets and are subject to regular semi-annual redeterminations. As of December 31, 2023, the borrowing base was $3.5 billion and lender commitments were $1.6 billion. The next redetermination of the borrowing base is scheduled to occur in April 2024. The maturity date of the Credit Facility is the earlier of (i) October 26, 2026 and (ii) the date that is 180 days prior to the earliest stated redemption date of any series of Antero's then outstanding Senior Notes.

As of December 31, 2023, we had an outstanding balance under the Credit Facility of $417 million and outstanding letters of credit of $501 million.

The Credit Facility provides for borrowing at either an Adjusted Term Secured Overnight Financing Rate ("SOFR"), an Adjusted Daily Simple SOFR or an Alternate Base Rate (each as defined in the Credit Facility).

The Credit Facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- pay dividends;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Credit Facility also requires us to maintain the following financial ratios (subject to certain exceptions). The current ratio and the leverage ratio are tested quarterly.

- a minimum consolidated current ratio of 1.00 to 1.00 at the end of each fiscal quarter; and
- a maximum leverage ratio of total debt to EBITDAX for the trailing four quarter period of 4.00 to 1.00 at the end of each fiscal quarter.

As of December 31, 2022 and 2023, we were in compliance with the applicable covenants and ratios under the Credit Facility.

See Note 7—Long Term Debt to the consolidated financial statements included in this Annual Report on Form 10-K for more information on our Credit Facility.

Senior Unsecured Notes

The following table summarizes certain material terms of our Senior Notes and 2026 Convertible Notes outstanding as of December 31, 2023:

	2026 Notes	2029 Notes	2030 Notes	2026 Convertible Notes
Outstanding principal (in thousands)	$ 96,870	$ 407,115	$ 600,000	$ 26,386
Interest rate	8.375 %	7.625 %	5.735 %	4.25 %
Maturity date	July 15, 2026	February 1, 2029	March 1, 2030	September 1, 2026
Interest payment dates	Jan. 15, July 15	Feb. 1, Aug. 1	Mar. 1, Sept. 1	Mar. 1, Sept. 1
Make-whole redemption date [1]	January 15, 2026	February 1, 2027	March 1, 2028	N/A [2]

(1) On or after these dates, we may redeem the applicable series of notes, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed, together with accrued and unpaid interest up to the redemption date. At any time prior to these dates, we may redeem the notes at a redemption price that includes an applicable premium as defined in the indentures to such notes.

(2) The indenture governing the 2026 Convertible Notes does not allow us to optionally redeem the 2026 Convertible Notes prior to the maturity date.

See Note 7—Long-Term Debt to the consolidated financial statements for more information.

We may, from time to time, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, open market purchases, privately negotiated transactions or otherwise. Any such repurchases will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved could be material. See Note 7—Long-Term Debt to the consolidated financial statements for more information.

The Senior Notes indentures each contain restrictive covenants and restrict our ability to incur additional debt unless a pro forma minimum interest coverage ratio requirement of 2.25:1 is maintained. We were in compliance with such covenants as of December 31, 2022 and 2023.

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. Any new accounting policies or updates to existing accounting policies as a result of new accounting pronouncements have been included in Note 2—Summary of Significant Accounting Policies to our consolidated financial statements. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosure of contingent liabilities. Accounting estimates and assumptions are considered to be critical if there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the reported amounts in our consolidated financial statements that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements.

Successful Efforts Method

We account for our natural gas, NGLs and oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill and complete productive wells, development wells and oil and gas leases are capitalized. Items charged to expense generally include exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases and costs associated with unsuccessful lease acquisitions.

Unproved properties with significant acquisition costs are assessed for impairment on a property by property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks and future plans to develop acreage. Impairment of oil and gas properties related to unproved properties for leases that have expired, or are expected to expire, was $91 million, $98 million and $51 million for the years ended December 31, 2021, 2022 and 2023, respectively.

We believe that the application of the successful efforts method of accounting requires judgment to determine the proper classification of wells designated as developmental or exploratory, which designation determines the proper accounting treatment of the costs incurred. In addition, evaluating our unproved properties for impairment involves significant judgments about future development plans, which include future sales prices of natural gas, NGLs and oil and future development and production costs, as well as the amount of natural gas, NGLs and oil recoveries.

Natural Gas, NGLs and Oil Reserve Quantities

Our internal technical staff prepares the estimates of natural gas, NGLs and oil reserves and associated future net cash flows, which are audited by our independent reserve engineers. The SEC has defined proved reserves as the estimated quantities of natural gas, NGLs and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved undeveloped reserves include reserves that are expected to be drilled and developed within five years; wells that are not drilled within five years from booking are reclassified from proved reserves to probable reserves. Reserves are used in our proved properties depletion calculation and in assessing the carrying value of our oil and gas properties.

Our independent reserve engineers and internal technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates consider recent production levels and other technical information about each reservoir. Natural gas, NGLs and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas, NGLs and oil that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, natural gas, NGLs and oil prices, cost changes, technological advances, new geological or geophysical data or other economic factors. Accordingly, reserve estimates are generally different from the quantities of natural gas, NGLs and oil that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions.

We believe that the estimates and assumptions related to reserve quantities is critical because any significant revisions or changes to these estimates and assumptions could affect the future amortization rates of capitalized proved property costs and result in a material asset impairment.

Impairment of Proved Properties

We evaluate the carrying amount of our proved natural gas, NGLs and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount of our proved properties exceeds the estimated undiscounted future net cash flows (measured using futures prices at the balance sheet date), we further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeds the estimated fair value of the properties. We did not record any impairments for proved properties during the years ended December 31, 2021, 2022 and 2023.

Based on current future commodity prices, we currently do not anticipate having to record any impairment charge for our proved properties in the near future. Estimated undiscounted future net cash flows are sensitive to commodity price swings and a decline in prices could result in the carrying amount exceeding the estimated undiscounted future net cash flows at the end of a future reporting period, which would require us to further evaluate if an impairment charge would be necessary. For our Utica and Marcellus properties, strip pricing would have to decline by more than 20% and 25%, respectively, from year end 2023 levels before further evaluation of those properties would be required in order to determine if an impairment charge is necessary. If future prices decline from December 31, 2023, the fair value of our properties may be below their carrying amounts and an impairment charge may be necessary. However, we are unable to predict commodity prices with any greater precision than the futures market.

We believe that the estimates and assumptions related to our undiscounted future net cash flows and the fair value of our proved properties is critical because different natural gas, NGLs and oil pricing, cost assumptions or discount rates, as applicable, may affect the recognition, timing and amount of an impairment and, if changed, could have a material effect on the Company's financial position and results of operations.

Derivative Instruments

In order to manage our exposure to natural gas, NGLs and oil price volatility, we may enter into derivative transactions from time to time, which agreements could include commodity fixed price swaps, basis swaps, collars or other similar instruments related to the price risk associated with our production. We record derivative instruments on the consolidated balance sheet as either assets or liabilities measured at fair value and record changes in the fair value of derivatives in current earnings as they occur. Our derivatives have not been designated as hedges for accounting purposes. Fair value measurements for our commodity derivatives require the use of assumptions and judgements including valuation techniques, future pricing, volatility, time to maturity and credit risk, among others. We regularly assess the reasonableness of these assumptions and judgements through the review of counterparty statements. However, changes to these assumptions and judgements could have a material effect on the Company's financial position and results of operations.

Income Taxes

Income taxes are accounted for using the asset and liability approach. Under this approach, deferred income tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis. We record deferred income tax expense to the extent our deferred income tax liabilities exceed our deferred income tax assets. We record a deferred income tax benefit to the extent our deferred income tax assets exceed our deferred income tax liabilities. We are subject to state and federal income taxes, but are currently not in a cash tax paying position with respect to federal income taxes.

We record a valuation allowance when we believe all or a portion of our deferred income tax assets will not be realized. In assessing the realizability of our deferred income tax assets, management considers whether some portion or all of the deferred income tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred income tax assets is dependent upon our ability to generate future taxable income during the periods in which our deferred income tax assets are deductible. Management considers the scheduled reversal of deferred income tax liabilities, projected future taxable income and tax planning strategies in making this assessment, estimates of which may be imprecise due to unforeseen future events or conditions outside of our control, including changes in commodity prices or changes to tax laws and regulations. The amount of deferred income tax assets considered realizable could change based upon the amounts of taxable income actually generated, or as estimates of future taxable income change. As of December 31, 2023, we have recognized a valuation allowance of $55 million related to Colorado, Oklahoma and West Virginia state NOL carryforwards that we do not expect to realize due to expected future reduced income tax apportionment in those states.

The calculation of deferred income tax assets and liabilities involves uncertainties in the application of complex tax laws and regulations. We recognize in our financial statements those tax positions which we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. We believe that the estimates and assumptions related to income taxes are critical because the assumptions and estimates required to assess the likelihood that our deferred income tax assets will be recovered from future taxable income, as well as the amount and timing of a valuation allowance on our deferred income tax assets is an exercise in judgement and susceptible to change as circumstances warrant. These assumptions affect deferred income tax liability and income tax expense and, if changed, could have a material effect on the Company's financial position and results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices, as well as interest rates. These disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas, NGLs and oil production. Pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production and the prevailing worldwide price for oil. Pricing for natural gas, NGLs and oil has, historically, been volatile and unpredictable, and we expect this volatility to continue in the future. The prices we receive for our production depend on many factors outside of our control, including volatility in the differences between commodity prices at sales points and the applicable index price.

We may enter into financial derivative instruments for a portion of our natural gas, NGLs and oil production when circumstances warrant and management believes that favorable future prices can be secured in order to mitigate some of the potential negative impact on our cash flows caused by changes in commodity prices. Due to our improved liquidity and leverage position as compared to historical levels, the percentage of our expected production that we hedge has decreased. For the years ended December 31, 2022 and 2023, 33% and 1%, respectively, of our production was hedged through fixed price commodity swaps, and as of December 31, 2023, we had no fixed price commodity swap positions. Our financial hedging activities may include commodity fixed price swaps, basis swaps, collars or other similar instruments related to the price risk associated with our production. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. As of December 31, 2023, our commodity derivatives included basis differential swaps, call options and embedded put options at index-based pricing for a portion of our production. See Note 11—Derivative Instruments to our consolidated financial statements for more information.

Under the Credit Facility, we are permitted to hedge up to 75% of our projected production for the next 60 months. We may enter into hedge contracts with a term greater than 60 months, and for no longer than 72 months, for up to 65% of our estimated production. Based on our production and our derivative instruments that settled during the year ended December 31, 2023, our revenues would have decreased by $148 million for each $0.10 decrease per MMBtu in natural gas prices and $1.00 decrease per Bbl in oil and NGLs prices, excluding the effects of changes in the fair value of our derivative positions which remain open as of December 31, 2023.

All derivative instruments, other than those that meet the normal purchase and normal sale scope exception or other derivative scope exceptions, are recorded at fair market value in accordance with GAAP and are included in our consolidated balance sheets as assets or liabilities. The fair values of our derivative instruments are adjusted for non-performance risk. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; therefore, all mark to market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations and comprehensive income (loss). We present total gains or losses on commodity derivatives (for both settled derivatives and derivative positions which remain open) within operating revenues as "Commodity derivative fair value gains (losses)."

Mark-to-market adjustments of derivative instruments cause earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled or monetized prior to settlement. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are impacted when the associated derivative contracts are settled or monetized by making or receiving payments to or from the counterparty. As of December 31, 2022 and 2023, the estimated fair value of our commodity derivative instruments was a net liability of $431 million, and $37 million, respectively, comprised of current and noncurrent assets and liabilities.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from the following: the sale of our natural gas, NGLs and oil production ($384 million as of December 31, 2023), which we market to energy companies, end users and refineries, and commodity derivative contracts ($17 million as of December 31, 2023).

We are subject to credit risk due to the concentration of our receivables from several significant customers for sales of natural gas, NGLs and oil. We generally do not require 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.

In addition, we are exposed to the credit risk of our counterparties for our derivative instruments. Credit risk is the potential failure of a counterparty to perform under the terms of a derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions that management deems to be competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have commodity hedges in place with three different counterparties, two of which are lenders under the Credit Facility. As of December 31, 2023, we did not have any derivative assets with bank counterparties under our Credit Facility. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the counterparties' respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) as of December 31, 2023. We believe that all of the counterparties to our derivative instruments are acceptable credit risks as of December 31, 2023. Other than as provided by the Credit Facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2023, we did not have any past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under the Credit Facility, which has a floating interest rate. The average annualized interest rate incurred on the Credit Facility for borrowings during the year ended December 31, 2023 was 7.6%. We estimate that a 1.0% increase in the applicable average interest rates for the year ended December 31, 2023 would have resulted in an estimated $3 million increase in interest expense.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Reports of Independent Registered Public Accounting Firm, Consolidated Financial Statements, and supplementary financial data required for this Item are set forth beginning on page F-2 of this Annual Report on Form 10-K and are incorporated herein by reference.

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

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures and is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2023 at a level of reasonable assurance.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The management of Antero Resources Corporation is responsible for establishing and maintaining adequate internal control over financial reporting for us as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of the assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect all misstatements. Further, because of changes in conditions, effectiveness of internal controls over financial reporting may vary over time.

Under the supervision of, and with the participation of, our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in *Internal Control—Integrated Framework* in 2013, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management of Antero Resources Corporation concluded that our internal control over financial reporting was effective as of December 31, 2023.

The effectiveness of our internal control over financial reporting as of December 31, 2023 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which appears beginning on page F-2 in this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2024 Annual Meeting of Stockholders.

Code of Ethics

We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K relating to amendments to or waivers from any provision of our Corporate Code of Business Conduct and Ethics applicable to our principal executive officer, principal financial officer, principal accounting officer and other persons performing similar functions by posting such information in the "Governance" subsection of our website at *www.anteroresources.com*.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2024 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2024 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2024 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered accounting firm is KPMG LLP, Denver, CO, Auditor Firm ID: 185.

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2024 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules

The consolidated financial statements are listed on the Index to Financial Statements to this Annual Report on Form 10-K beginning on page F-1.

(a)(3) Exhibits.

Exhibit Number	Description of Exhibit
2.1	Simplification Agreement, dated as of October 9, 2018, by and among AMGP GP LLC, Antero Midstream GP LP, Antero IDR Holdings LLC, Arkrose Midstream Preferred Co LLC, Arkrose Midstream NewCo Inc., Arkrose Midstream Merger Sub LLC, Antero Midstream Partners GP LLC and Antero Midstream Partners LP (incorporated by reference to Exhibit 2.1 to Antero Midstream GP LP's Current Report on Form 8-K (Commission File No. 001-38075) filed on October 10, 2018).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of Antero Resources Corporation, dated June 8, 2023 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on June 8, 2023).
3.3	Second Amended and Restated Bylaws of Antero Resources Corporation, dated February 14, 2023 (incorporated by reference to Exhibit 3.2 to the Company's Annual Report on Form 10-K (Commission File No. 0001-36120) filed on February 15, 2023).
4.1	Indenture related to the 4.25% Convertible Senior Notes due 2026, dated as of August 21, 2020, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on August 21, 2020).
4.2	Form of 4.25% Convertible Senior Note due 2026 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on August 21,2020).
4.3	Indenture related to the 8.375% Senior Notes due 2026, dated as of January 4, 2021, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on January 4, 2021).
4.4	Form of 8.375% Senior Note due 2026 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on January 4, 2021).
4.5	Registration Rights Agreement, dated as of October 16, 2013, by and among Antero Resources Corporation and the owners of the membership interests in Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.6*	Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended.
4.7	Indenture related to the 7.625% Senior Notes due 2029, dated as of January 26, 2021, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on February 1, 2021).
4.8	Form of 7.625% Senior Note due 2029 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on February 1, 2021).
4.9	Indenture related to the 5.375% Senior Notes due 2030, dated as of June 1, 2021, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on June 1, 2021).
4.10	Form of 5.375% Senior Note due 2030 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on June 1, 2021).
10.1	Contribution Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero

Exhibit Number	Description of Exhibit
	Resources Midstream LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.2	Amended and Restated Contribution Agreement, dated as of November 10, 2014, by and between Antero Resources Corporation and Antero Midstream Partners LP (incorporated by reference to Exhibit 10.1 to Antero Midstream Partners LP's Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.3	Agreement and Plan of Merger, dated as of October 1, 2013, by and among Antero Resources Corporation, Antero Resources LLC and Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 333-164876) filed on October 11, 2013).
10.4	Second Amended and Restated Gathering and Compression Agreement, dated as of December 8, 2019, by and between Antero Resources Corporation and Antero Midstream LLC (incorporated by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 12, 2020).
10.5	Second Amended and Restated Right of First Offer Agreement, dated as of February 13, 2018, by and between Antero Resources Corporation and Antero Midstream LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 25, 2018).
10.6	License Agreement, dated as of November 10, 2014, by and between Antero Resources Corporation and Antero Midstream Partners LP (incorporated by reference to Exhibit 10.4 to Antero Midstream Partners LP's Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.7	Amended and Restated Secondment Agreement, effective as of March 13, 2019, by and between Antero Midstream Corporation, Antero Midstream Partners LP, Antero Midstream Partners GP LLC, Antero Midstream LLC, Antero Water LLC, Antero Treatment LLC and Antero Resources Corporation (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 12, 2020).
10.8	Second Amended and Restated Services Agreement, effective as of March 13, 2019, by and among Antero Midstream Partners LP, Antero Midstream Corporation, Antero Midstream Partners GP LLC and Antero Resources Corporation (incorporated by reference to Exhibit 10.8 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 12, 2020).
10.9**	Amended and Restated Water Services Agreement dated as of February 12, 2019, by and between Antero Resources Corporation and Antero Water LLC (incorporated by reference to Exhibit 10.9 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 13, 2019).
10.10	Lender Certificate, dated October 29, 2019, delivered by Royal Bank of Canada, and agreed to and accepted by JPMorgan Chase Bank, N.A., as Administrative Agent, and Antero Resources Corporation (incorporated by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 12, 2020).
10.11	Sixth Amended and Restated Credit Facility, dated as of October 26, 2021, by and among Antero Resources Corporation, as Borrower, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 27, 2021).
10.12†	Form of Amended and Restated Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on April 17, 2018).
10.13†	Antero Resources Corporation Long-Term Incentive Plan, effective as of October 1, 2013 (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (Commission File No. 001-36120) filed on October 11, 2013).
10.14†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 25, 2015).
10.15†	Global Amendment to Grant Notices and Award Agreements Under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).
10.16†	Form of Stock Award Grant Notice and Stock Award Agreement (Form for Non-Employee Directors) under the Antero Resources Corporation 2020 Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form S-8 (Commission File No. 001-36120) filed on July 9, 2020).
10.17†	Stockholders' Agreement, dated as of October 9, 2018, by and among Antero Midstream GP LP, Arkrose Subsidiary Holdings LLC, Warburg Pincus Private Equity X O&G, L.P., Warburg Pincus X Partners, L.P., Warburg Pincus Private Equity VIII, LP, Warburg Pincus Netherlands Private Equity VIII C.V.I. WP-WPVIII Investors, L.P., Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., Yorktown Energy Partners VIII, L.P., Paul M. Rady, Mockingbird Investment, LLC, Glen C. Warren, Jr. and Canton Investment Holdings LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 10, 2018).

Exhibit Number	Description of Exhibit
10.18†	Registration Rights Agreement, dated March 12, 2019, by and among Antero Midstream Corporation, the Company, Arkrose Subsidiary Holdings LLC, Glen C. Warren, Jr., Canton Investment Holdings LLC, Paul M. Rady, Mockingbird Investments, LLC and other holders named therein (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on March 13, 2019).
10.19†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Form for Special Retention Awards) under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 29, 2020).
10.20†	Form of Retention Award Grant Notice and Retention Award Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 29, 2020).
10.21†	Antero Resources Corporation 2020 Long-Term Incentive Plan, effective June 17, 2020 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on June 23, 2020).
10.22†	Form of Retention Award Grant Notice and Retention Award Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (Employees) (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2020).
10.23†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2020).
10.24†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2020).
10.25†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 28, 2021).
10.26†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 27, 2022).
21.1*	Subsidiaries of Antero Resources Corporation.
22.1*	List of Guarantor Subsidiaries.
23.1*	Consent of KPMG LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
95.1*	Federal Mine Safety and Health Act Information.
97.1*	Antero Resources Corporation Incentive Compensation Recovery Policy.
99.1*	Report of DeGolyer and MacNaughton, dated as of January 17, 2024, for proved reserves as of December 31, 2023.
99.2	Report of DeGolyer and MacNaughton, dated as of January 17, 2023, for proved reserves as of December 31, 2022 (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 15, 2023).
99.3	Report of DeGolyer and MacNaughton, dated as of January 21, 2022, for proved reserves as of December 31, 2021 (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 16, 2022).

Exhibit Number	Description of Exhibit
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2023, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Consolidated Statements of Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document).

The exhibits marked with the asterisk symbol (*) are filed or furnished with this Annual Report on Form 10-K.
** Portions of this exhibit have been omitted pursuant to a request for confidential treatment.
† Management contract or compensatory plan or arrangement.

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.

ANTERO RESOURCES CORPORATION

By: /s/ MICHAEL N. KENNEDY
Michael N. Kennedy
Chief Financial Officer and Senior Vice President – Finance

Date: February 14, 2024

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ PAUL M. RADY Paul M. Rady	Chairman of the Board, Director, Chief Executive Officer and President (principal executive officer)	February 14, 2024
/s/ MICHAEL N. KENNEDY Michael N. Kennedy	Chief Financial Officer and Senior Vice President – Finance (principal financial officer)	February 14, 2024
/s/ SHERI L. PEARCE Sheri L. Pearce	Senior Vice President – Accounting and Chief Accounting Officer (principal accounting officer)	February 14, 2024
/s/ ROBERT J. CLARK Robert J. Clark	Director	February 14, 2024
/s/ BENJAMIN A. HARDESTY Benjamin A. Hardesty	Director	February 14, 2024
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 14, 2024
/s/ JACQUELINE C. MUTSCHLER Jacqueline C. Mutschler	Director	February 14, 2024
/s/ BRENDA R. SCHROER Brenda R. Schroer	Director	February 14, 2024
/s/ VICKY SUTIL Vicky Sutil	Director	February 14, 2024
/s/ THOMAS B. TYREE, JR. Thomas B. Tyree, Jr.	Director	February 14, 2024

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Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors
Antero Resources Corporation:

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of Antero Resources Corporation and subsidiaries (the Company) as of December 31, 2022 and 2023, the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control –Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2023, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023 based on criteria established in Internal Control –Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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.

Critical Audit Matter

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

Estimated oil and gas reserves impact on depletion expense related to proved oil and gas properties

As discussed in Note 2 to the consolidated financial statements, the Company calculates depletion expense related to proved oil and gas properties using the units-of-production method. Under such method, capitalized costs are amortized over total estimated proved oil and gas reserves. For the year ended December 31, 2023, the Company recorded depletion expense related to proved oil and gas properties of $682 million. Estimating proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration forecasted production and operating cost assumptions. The Company engages external reservoir engineering specialists to perform an independent evaluation of those proved oil and gas reserve estimates.

We identified the assessment of the impact of estimated oil and gas reserves on depletion expense related to proved oil and gas properties as a critical audit matter. Complex auditor judgment was required in evaluating the Company's estimate of total proved oil and gas reserves, which is an input in the depletion expense calculation. Auditor judgment was also required to evaluate the significant assumptions used by the Company related to forecasted production, estimated future operating costs, and oil and gas prices inclusive of market differentials because changes to these assumptions could have a significant impact on the estimated oil and gas reserves.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the Company's depletion expense process, including certain controls related to the estimation of proved oil and gas reserves used in the depletion expense calculation. We evaluated (1) the professional qualifications of the Company's internal reservoir engineers as well as the external reservoir engineering specialists and external engineering firm, (2) the knowledge, skill, and ability of the Company's internal and external reservoir engineers, and (3) the relationship of the external reservoir engineering specialists and external engineering firm to the Company. We analyzed and recalculated depletion expense for compliance with industry and regulatory standards. We assessed the methodology used by the Company's internal reservoir engineers to estimate proved oil and gas reserves, and the methodology used by the external reservoir engineering specialists to evaluate those reserve estimates for compliance with industry and regulatory standards. We compared the forecasted production assumptions used by the internal reservoir engineers to historical production rates. We evaluated the operating cost assumptions utilized by the internal reservoir engineers by comparing them to historical costs. We evaluated the oil and gas prices utilized by the internal reservoir engineers by comparing them to publicly available prices and tested the relevant market differentials. We read and considered the findings of the Company's external reservoir engineering specialists in connection with our evaluation of the Company's reserve estimates.

/s/ KPMG LLP

We have served as the Company's auditor since 2003.

Denver, Colorado
February 14, 2024

ANTERO RESOURCES CORPORATION
Consolidated Balance Sheets
(In thousands, except per share amounts)

	December 31, 2022	December 31, 2023
Assets		
Current assets:		
Accounts receivable	$ 35,488	42,619
Accrued revenue	707,685	400,805
Derivative instruments	1,900	5,175
Prepaid expenses	10,580	12,901
Other current assets	31,872	14,192
Total current assets	787,525	475,692
Property and equipment:		
Oil and gas properties, at cost (successful efforts method):		
Unproved properties	997,715	974,642
Proved properties	13,234,777	13,908,804
Gathering systems and facilities	5,802	5,802
Other property and equipment	83,909	98,668
	14,322,203	14,987,916
Less accumulated depletion, depreciation and amortization	(4,683,399)	(5,063,274)
Property and equipment, net	9,638,804	9,924,642
Operating leases right-of-use assets	3,444,331	2,965,880
Derivative instruments	9,844	5,570
Investment in unconsolidated affiliate	220,429	222,255
Other assets	17,106	25,375
Total assets	$ 14,118,039	13,619,414
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 77,543	38,993
Accounts payable, related parties	80,708	86,284
Accrued liabilities	461,788	381,340
Revenue distributions payable	468,210	361,782
Derivative instruments	97,765	15,236
Short-term lease liabilities	556,636	540,060
Deferred revenue, VPP	30,552	27,101
Other current liabilities	1,707	1,295
Total current liabilities	1,774,909	1,452,091
Long-term liabilities:		
Long-term debt	1,183,476	1,537,596
Deferred income tax liability, net	759,861	834,268
Derivative instruments	345,280	32,764
Long-term lease liabilities	2,889,854	2,428,450
Deferred revenue, VPP	87,813	60,712
Other liabilities	59,692	59,431
Total liabilities	7,100,885	6,405,312
Commitments and contingencies		
Equity:		
Stockholders' equity:		
Preferred stock, $0.01 par value; authorized - 50,000 shares; none issued	—	—
Common stock, $0.01 par value; authorized - 1,000,000 shares; 297,393 shares issued and 297,359 shares outstanding as of December 31, 2022, and 303,544 shares issued and outstanding as of December 31, 2023	2,974	3,035
Additional paid-in capital	5,838,848	5,846,541
Retained earnings	913,896	1,131,828
Treasury stock, at cost; 34 shares and zero shares as of December 31, 2022 and 2023, respectively	(1,160)	—
Total stockholders' equity	6,754,558	6,981,404
Noncontrolling interests	262,596	232,698
Total equity	7,017,154	7,214,102
Total liabilities and equity	$ 14,118,039	13,619,414

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income (Loss)

(In thousands, except per share amounts)

	Year Ended December 31,		
	2021	**2022**	**2023**
Revenue and other:			
Natural gas sales	$ 3,442,028	5,520,419	2,192,349
Natural gas liquids sales	2,147,499	2,498,657	1,836,950
Oil sales	201,232	275,673	247,146
Commodity derivative fair value gains (losses)	(1,936,509)	(1,615,836)	166,324
Marketing	718,921	416,758	206,122
Amortization of deferred revenue, VPP	45,236	37,603	30,552
Other revenue and income	1,025	5,162	2,529
Total revenue	4,619,432	7,138,436	4,681,972
Operating expenses:			
Lease operating	96,793	99,595	118,441
Gathering, compression, processing and transportation	2,499,174	2,605,380	2,642,358
Production and ad valorem taxes	197,910	287,406	158,855
Marketing	811,698	531,304	284,965
Exploration and mine expenses	6,566	7,409	2,700
General and administrative (including equity-based compensation expense of $20,437, $35,443 and $59,519 in 2021, 2022 and 2023, respectively)	145,006	172,909	224,516
Depletion, depreciation and amortization	742,009	680,600	689,966
Impairment of property and equipment	90,523	149,731	51,302
Accretion of asset retirement obligations	3,820	4,627	3,244
Contract termination and loss contingency	4,305	25,099	52,606
Loss (gain) on sale of assets	(2,232)	471	(447)
Other operating expense	—	—	336
Total operating expenses	4,595,572	4,564,531	4,228,842
Operating income	23,860	2,573,905	453,130
Other income (expense):			
Interest expense, net	(181,868)	(125,372)	(117,870)
Equity in earnings of unconsolidated affiliate	77,085	72,327	82,952
Loss on early extinguishment of debt	(93,191)	(46,027)	—
Loss on convertible note inducements and equitizations	(50,777)	(169)	(374)
Transaction expense	(3,295)	—	—
Total other expense	(252,046)	(99,241)	(35,292)
Income (loss) before income taxes	(228,186)	2,474,664	417,838
Income tax benefit (expense)	74,077	(448,692)	(75,994)
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(154,109)	2,025,972	341,844
Less: net income and comprehensive income attributable to noncontrolling interests	32,790	127,201	98,925
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (186,899)	1,898,771	242,919
Net income (loss) per common share—basic	$ (0.61)	6.18	0.81
Net income (loss) per common share—diluted	$ (0.61)	5.78	0.78
Weighted average number of common shares outstanding:			
Basic	308,146	307,202	299,793
Diluted	308,146	329,223	311,597

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Equity

(In thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Treasury Stock		Noncontrolling Interests	Total Equity
	Shares	Amount			Shares	Amount		
Balances, December 31, 2020	268,672	$ 2,686	6,195,497	(430,478)	—	$ —	322,566	6,090,271
Issuance of common shares	42,976	430	363,813	—	—	—	—	364,243
Issuance of common units in Martica Holdings, LLC	—	—	—	—	—	—	51,000	51,000
Equity component of 2026 Convertible Notes, net	—	—	(195,056)	—	—	—	—	(195,056)
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	2,282	23	(13,293)	—	—	—	—	(13,270)
Equity-based compensation	—	—	20,437	—	—	—	—	20,437
Distributions to noncontrolling interests	—	—	—	—	—	—	(97,424)	(97,424)
Net income (loss) and comprehensive income (loss)	—	—	—	(186,899)			32,790	(154,109)
Balances, December 31, 2021	313,930	3,139	6,371,398	(617,377)	—	—	308,932	6,066,092
Equity component of 2026 Convertible Notes, net	—	—	(24,411)	3,229	—	—	—	(21,182)
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	2,971	30	(66,162)	—	—	—	—	(66,132)
Conversion of 2026 Convertible Notes	5,672	57	24,185	—				24,242
Repurchases and retirements of common stock	(25,180)	(252)	(501,605)	(370,727)	(34)	(1,160)	—	(873,744)
Equity-based compensation	—	—	35,443	—	—	—	—	35,443
Distributions to noncontrolling interests	—	—	—	—	—	—	(173,537)	(173,537)
Net income and comprehensive income	—	—	—	1,898,771		—	127,201	2,025,972
Balances, December 31, 2022	297,393	2,974	5,838,848	913,896	(34)	(1,160)	262,596	7,017,154
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,735	17	(30,384)	—	—	—	—	(30,367)
Conversion of 2026 Convertible Notes	7,032	70	30,061	—	—	—	—	30,131
Repurchases and retirements of common stock	(2,616)	(26)	(51,503)	(24,987)	34	1,160	—	(75,356)
Equity-based compensation	—	—	59,519	—	—	—	—	59,519
Distributions to noncontrolling interests	—	—	—	—	—	—	(128,823)	(128,823)
Net income and comprehensive income	—	—	—	242,919	—	—	98,925	341,844
Balances, December 31, 2023	303,544	$ 3,035	5,846,541	1,131,828	—	$ —	232,698	7,214,102

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION
Consolidated Statements of Cash Flows
(In thousands)

	Year Ended December 31,		
	2021	2022	2023
Cash flows provided by (used in) operating activities:			
Net income (loss) including noncontrolling interests	$ (154,109)	2,025,972	341,844
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	745,829	685,227	693,210
Impairments	90,523	149,731	51,302
Commodity derivative fair value losses (gains)	1,936,509	1,615,836	(166,324)
Losses on settled commodity derivatives	(1,183,400)	(1,911,065)	(25,383)
Payments for derivative monetizations	(4,569)	—	(202,339)
Deferred income tax expense (benefit)	(74,293)	447,845	74,407
Equity-based compensation expense	20,437	35,443	59,519
Equity in earnings of unconsolidated affiliate	(77,085)	(72,327)	(82,952)
Dividends of earnings from unconsolidated affiliate	136,609	125,138	125,138
Amortization of deferred revenue	(45,236)	(37,603)	(30,552)
Amortization of debt issuance costs, debt discount and other	12,492	4,336	2,264
Settlement of asset retirement obligations	—	(1,050)	(718)
Contract termination and loss contingency	—	—	12,100
Loss (gain) on sale of assets	(2,232)	471	(447)
Loss on early extinguishment of debt	93,191	46,027	—
Loss on convertible note inducements and equitizations	50,777	169	374
Changes in current assets and liabilities:			
Accounts receivable	(55,567)	43,510	7,550
Accrued revenue	(166,128)	(116,243)	306,880
Prepaid expenses and other current assets	316	(27,530)	14,890
Accounts payable including related parties	(1,184)	32,374	(16,837)
Accrued liabilities	77,584	(5,620)	(62,419)
Revenue distributions payable	246,757	23,337	(106,429)
Other current liabilities	12,895	(12,636)	(357)
Net cash provided by operating activities	1,660,116	3,051,342	994,721
Cash flows provided by (used in) investing activities:			
Additions to unproved properties	(79,138)	(149,009)	(151,135)
Drilling and completion costs	(601,175)	(780,649)	(964,346)
Additions to other property and equipment	(35,623)	(14,313)	(16,382)
Proceeds from asset sales	3,192	2,747	447
Change in other assets	2,632	(2,388)	(9,351)
Change in other liabilities	(672)	—	—
Net cash used in investing activities	(710,784)	(943,612)	(1,140,767)
Cash flows provided by (used in) financing activities:			
Repurchases of common stock	—	(873,744)	(75,355)
Issuance of senior notes	1,800,000	—	—
Repayment of senior notes	(1,554,657)	(1,027,559)	—
Borrowings on Credit Facility	5,006,000	6,308,900	4,501,400
Repayments on Credit Facility	(6,023,000)	(6,274,100)	(4,119,000)
Payment of debt issuance costs	(31,474)	(814)	(605)
Sale of noncontrolling interest	51,000	—	—
Distributions to noncontrolling interests	(97,424)	(173,537)	(128,823)
Employee tax withholding for settlement of equity compensation awards	(13,270)	(66,132)	(30,367)
Convertible note inducements and equitizations	(85,648)	(169)	(374)
Other	(859)	(575)	(830)
Net cash provided by (used in) financing activities	(949,332)	(2,107,730)	146,046
Net increase in cash and cash equivalents	—	—	—
Cash and cash equivalents, beginning of period	—	—	—
Cash and cash equivalents, end of period	$ —	—	—
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 141,930	155,006	113,910
Increase (decrease) in accounts payable and accrued liabilities for additions to property and equipment	$ 37,049	38,035	(60,762)

See accompanying notes to consolidated financial statements.

(1) Organization

Antero Resources Corporation (individually referred to as "Antero" and together with its consolidated subsidiaries "Antero Resources," or the "Company") is engaged in the development, production, exploration and acquisition of natural gas, NGLs and oil properties in the Appalachian Basin in West Virginia and Ohio. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs and oil from unconventional formations. The Company's corporate headquarters is located in Denver, Colorado.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared in accordance with GAAP. In the opinion of management, the accompanying consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of December 31, 2022 and 2023, and its results of operations and cash flows for the years ended December 31, 2021, 2022 and 2023. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is equal to its comprehensive income or loss.

(b) Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Antero Resources Corporation, its wholly owned subsidiaries and its VIE, Martica, for which the Company is the primary beneficiary. All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements.

For the years ended December 31, 2021, 2022 and 2023, the Company determined that Martica is a VIE for which Antero is the primary beneficiary. Therefore, Martica's accounts are consolidated in the Company's consolidated financial statements. Antero is the primary beneficiary of Martica based on its power to direct the activities that most significantly impact Martica's economic performance, and its obligation to absorb losses of, or right to receive benefits from, Martica that could be significant to Martica. In reaching such determination that Antero is the primary beneficiary of Martica, the Company considered the following:

- Martica was formed to hold certain overriding royalty interests across the Company's existing asset base;
- substantially all of Martica's revenues are derived from production from the Company's natural gas, NGLs and oil properties in the Appalachian Basin in West Virginia and Ohio;
- Antero owns the Class B Units in Martica, which entitle Antero to receive distributions in respect of the Incremental Override (as defined in Note 3—Transactions); and
- Antero provides accounting, administrative and other services to Martica under a Management Services Agreement.

The Company accounts for its interest in Antero Midstream Corporation ("Antero Midstream") using the equity method of accounting. As of December 31, 2022 and 2023, the Company had 29.1% and 29.0%, respectively, interest in Antero Midstream. Investments in entities for which the Company exercises significant influence, but not control, are accounted for under the equity method. The Company's judgment regarding the level of influence over its equity method investments includes considering key factors such as Antero's ownership interest, representation on the board of directors and participation in the policy-making decisions of equity method investees. Such investments are included in Investment in unconsolidated affiliate on the Company's consolidated balance sheets. Income (loss) from investees that are accounted for under the equity method is included in Equity in earnings (loss) of unconsolidated affiliate on the Company's consolidated statements of operations and comprehensive income (loss) and cash flows. When Antero records its proportionate share of net income or net loss, it is recorded in equity in earnings (loss) of unconsolidated affiliate in the statements of operations and comprehensive income (loss) and the carrying value of that investment on the Company's balance sheet. When a distribution is received, it is recorded as a reduction to the carrying value of that investment on the Company's balance sheet. The Company's equity in earnings of unconsolidated affiliates is adjusted for intercompany transactions and the basis differences recognized due to the difference between the cost of the equity method investment in Antero Midstream and the amount of underlying equity in the net assets of Antero Midstream Partners LP ("Antero Midstream Partners") as of March 12, 2019, on such date, the Company deconsolidated Antero Midstream Partners. See Note 5—Equity Method Investments to the consolidated financial statements for further discussion on equity method investments.

The Company accounts for distributions received from equity method investees under the "nature of the distribution" approach. Under this approach, distributions received from equity method investees are classified on the basis of the nature of the activity or activities of the investee that generated the distribution as either a return on investment (classified as cash inflows from operating activities) or a return of investment (classified as cash inflows from investing activities).

(c) Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingent assets and liabilities. Changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results could differ from those estimates.

The Company's consolidated financial statements are based on a number of significant estimates, including estimates of natural gas, NGLs and oil reserve quantities, which are the basis for the calculation of depletion and impairment of oil and gas properties. Reserve estimates, by their nature, are inherently imprecise. Other items in the Company's consolidated financial statements that involve the use of significant estimates include derivative assets and liabilities, accrued revenue, deferred and current income taxes, asset retirement obligations and commitments and contingencies.

(d) Risks and Uncertainties

The markets for natural gas, NGLs and oil have, and continue to, experience significant price fluctuations. Price fluctuations can result from variations in weather, levels of production, availability of storage capacity transportation to other regions of the country, the level of imports to and exports from the United States and various other factors. Increases or decreases in the prices the Company receives for its production could have a significant impact on the Company's future results of operations and reserve quantities.

(e) Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short term nature of these instruments. From time to time, the Company may be in the position of a "book overdraft" in which outstanding checks exceed cash and cash equivalents. The Company classifies book overdrafts in accounts payable and revenue distributions payable within its consolidated balance sheets, and classifies the change in accounts payable associated with book overdrafts as an operating activity within its consolidated statements of cash flows. As of December 31, 2022, the book overdrafts included within accounts payable and revenue distributions payable were $28 million and $43 million, respectively. As of December 31, 2023, the book overdrafts included within accounts payable and revenue distributions payable were $11 million and $19 million, respectively.

(f) Oil and Gas Properties

The Company accounts for its natural gas, NGLs and oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill and complete productive wells, development wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are expensed as incurred. Exploratory drilling costs are initially capitalized, but expensed if the Company determines that the well does not contain reserves in commercially viable quantities. The Company reviews exploration costs related to wells-in-progress at the end of each quarter and determines, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or expensed. The sale of a partial interest in a proved property is accounted for as a normal retirement, and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties are assessed for impairment on a property-by-property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, commodity price outlooks, future plans to develop acreage, drilling results and reservoir performance of wells in the area. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on, or otherwise attributed to, the property. Proceeds from sales of partial interests in unproved properties are accounted for as a cost recovery without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties was $91 million, $98 million and $51 million for the years ended December 31, 2021, 2022 and 2023, respectively.

The Company evaluates the carrying amount of its proved natural gas, NGLs and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company would estimate the fair value of its properties and record an impairment expense for any excess of the carrying amount of the properties over the estimated fair value of the properties. Factors used to estimate fair value may include estimates of proved reserves, estimated future commodity prices, future production estimates and anticipated capital expenditures, using a commensurate discount rate. The Company did not incur any impairment expenses associated with its proved properties during the years ended December 31, 2021, 2022 and 2023.

As of December 31, 2023, the Company did not have capitalized costs related to exploratory wells-in-progress that have been deferred for longer than one year pending determination of proved reserves.

Depletion of oil and gas properties is calculated on a geological reservoir basis using the units-of-production method. Depletion expense for oil and gas properties was $736 million, $738 million and $682 million for the years ended December 31, 2021, 2022 and 2023, respectively.

(g) Impairment of Long-Lived Assets Other than Oil and Gas Properties

The Company evaluates its long-lived assets other than oil and gas properties for impairment when events or changes in circumstances indicate that the related carrying values of the assets may not be recoverable. Generally, the basis for making such assessments is undiscounted future cash flow projections for the assets being assessed. If the carrying values of the assets are deemed not recoverable, the carrying values are reduced to the estimated fair values, which are based on discounted future cash flows using assumptions as to revenues, costs and discount rates typical of third-party market participants, which is a Level 3 fair value measurement. In December 2022, the Company commenced a strategic evaluation of the sand mine at which time, such mine was idled. Accordingly, the Company performed an impairment analysis as of December 31, 2022, and recorded impairment expense of $48 million. There were no such impairments for the years ended December 31, 2021 and 2023.

(h) Other Property and Equipment

Other property and equipment assets are depreciated using the straight-line method over their estimated useful lives, which range from two to 20 years. Depreciation expense for other property and equipment was $6 million, $4 million and $8 million for the years ended December 31, 2021, 2022 and 2023, respectively. A gain or loss is recognized upon the sale or disposal of other property and equipment.

(i) Debt Issuance Costs

Debt issuance costs represent loan origination fees and other initial borrowing costs. Such costs are capitalized and included in Other assets on the consolidated balance sheets if related to the Company's Credit Facility, and are included as a reduction to Long-term debt on the consolidated balance sheets if related to the issuance of the Company's Senior Notes and 2026 Convertible Notes. These costs are amortized over the term of the related debt instrument. The Company charges expense for unamortized debt issuance costs if the credit facility is retired prior to its maturity date. As of December 31, 2022, the Company had $6 million of unamortized debt issuance costs included in other long-term assets, and $12 million of unamortized debt issuance costs included as a reduction to long-term debt. As of December 31, 2023, the Company had $5 million of unamortized debt issuance costs included in other long-term assets, and $10 million of unamortized debt issuance costs included as a reduction to long-term debt. The amortization and write-off related to deferred debt issuance costs was $7 million, $4 million and $4 million for the years ended December 31, 2021, 2022 and 2023, respectively.

(j) Derivative Financial Instruments

In order to manage its exposure to natural gas, NGLs and oil price volatility, the Company may enter into derivative transactions from time to time, which contracts may include commodity fixed price swaps, basis swaps, collars and other similar agreements related to the price risk associated with the Company's production. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent that the counterparty is unable to satisfy its settlement obligations. Cash flows from derivative instruments are classified in operating activities on the Company's consolidated statements of cash flows. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative positions.

The Company records derivative instruments on the consolidated balance sheets as either assets or liabilities measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives, including gains or losses on settled derivatives, are classified as revenues on the Company's consolidated statements of operations and comprehensive income (loss). The Company's derivatives have not been designated as hedges for accounting purposes.

(k) Asset Retirement Obligations

The Company is obligated to dispose of certain long-lived assets upon their abandonment. The Company's asset retirement obligations ("AROs") relate primarily to its obligation to plug and abandon oil and gas wells at the end of their lives. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations, which is then discounted at the Company's credit-adjusted, risk-free interest rate. Revisions to estimated AROs often result from changes in retirement cost estimates or changes in the estimated timing of abandonment. The fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense.

(l) Environmental Liabilities

Environmental expenditures that relate to an existing condition caused by past operations, and that do not contribute to current or future revenue generation, are expensed as incurred. Liabilities are accrued when environmental assessments and/or clean-up is probable and the costs can be reasonably estimated. These liabilities are adjusted as additional information becomes available or circumstances change. As of December 31, 2022 and 2023, the Company did not have a material amount accrued for any environmental liabilities, nor has the Company been cited for any environmental violations that it believes are likely to have a material adverse effect on its financial position, results of operations or cash flows.

(m) Natural Gas, NGLs and Oil Revenues

The Company's revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from the Company's natural gas. Sales of natural gas, NGLs and oil are recognized when the Company satisfies a performance obligation by transferring control of a product to a customer. Payment is generally received in the month following the sale.

Under the Company's natural gas sales contracts, it delivers natural gas to the purchaser at an agreed upon delivery point. Natural gas is transported from the wellheads to delivery points specified under sales contracts. To deliver natural gas to these points, Antero Midstream or other third parties gather, compress, process and transport the Company's natural gas. The Company maintains control of the natural gas during gathering, compression, processing and transportation. The Company's sales contracts provide that it receives a specific index price adjusted for pricing differentials. The Company transfers control of the product at the delivery point and recognizes revenue based on the contract price. The costs incurred to gather, compress, process and transport natural gas are recorded as Gathering, compression, processing and transportation expense on the Company's consolidated statements of operations and comprehensive income (loss).

NGLs, which are extracted from natural gas through processing, are either sold by the Company directly or by the processor under processing contracts. For NGLs sold by the Company directly, the sales contracts primarily provide that the Company delivers the product to the purchaser at an agreed upon delivery point and that it receives a specific index price adjusted for pricing differentials. The Company transfers control of the product to the purchaser at the delivery point and recognizes revenue based on the contract price. The costs incurred to process and transport NGLs are recorded as Gathering, compression, processing and transportation expense. For NGLs sold by the processor, the Company's processing contracts provide that the Company transfers control to the processor at the tailgate of the processing plant and it recognizes revenue based on the price received from the processor.

Under the Company's oil sales contracts, Antero Resources' generally sells oil to purchasers and collects a contractually agreed upon index price, net of pricing differentials. The Company recognizes revenue based on the contract price when it transfers control of the product to a purchaser. When applicable, the costs incurred to transport oil to a purchaser are recorded as Gathering, compression, processing and transportation expense on the Company's consolidated statements of operations and comprehensive income (loss).

(n) Marketing Revenues and Expenses

Marketing revenues are derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties. The Company retains control of the purchased natural gas and NGLs prior to delivery to the purchaser. The Company has concluded that it is the principal in these arrangements and therefore, the Company recognizes revenue on a gross basis, with costs to purchase and transport natural gas and NGLs presented as marketing expenses. Contracts to sell third-party gas and NGLs are generally subject to similar terms as contracts to sell the Company's produced natural gas and NGLs. The Company satisfies performance obligations to the purchaser by transferring control of the product at the delivery point and recognizes revenue based on the contract price received from the purchaser. Fees generated from the sale of excess firm transportation marketed to third parties are included in Marketing revenue on the Company's consolidated statements of operations and comprehensive income (loss).

Marketing expenses include the cost of purchased third-party natural gas and NGLs. The Company classifies firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize the capacity (excess capacity) as marketing expenses since it is marketing this excess capacity to third parties. Firm transportation for which the Company has sufficient production capacity (even though it may not use the transportation capacity because of alternative delivery points with more favorable pricing) is considered unutilized capacity and is charged to transportation expense on the Company's consolidated statements of operations.

(o) Deferred Revenue

Under the terms of the Company's volumetric production payment transaction ("VPP"), the Company is obligated to deliver certain natural gas volumes from specified wells to an overriding royalty interest owner over the term of the arrangement. The Company has accounted for the VPP as a conveyance under FASB ASC Topic 932, *Extractive Industries—Oil and Gas* ("ASC 932"), which requires the net proceeds to be recorded as deferred revenue due to the Company's future performance obligations. Revenue is recognized as volumes are delivered using the units-of-production method over the term of the VPP in Amortization of deferred revenue on the Company's consolidated statements of operations and comprehensive income (loss).

(p) Concentrations of Credit Risk

The Company's revenues are derived principally from uncollateralized sales to purchasers in the oil and gas industry or the utilities industry. The concentration of credit risk in two related industries affects the Company's overall exposure to credit risk because purchasers may be similarly affected by changes in economic and other conditions. The Company has not experienced significant credit losses on its receivables. The Company's sales to Six One Commodities LLC accounted for 10% and 12% of total sales for the years ended December 31, 2021 and 2022, respectively. No customer accounted for more than 10% of the Company's sales for the year ended December 31, 2023.

The Company is also exposed to credit risk on its commodity derivative portfolio. Any default by the counterparties to these derivative contracts when they become due could have a material adverse effect on the Company's financial condition and results of operations. The Company has economic hedges in place with three different counterparties. As of December 31, 2023, the Company did not have any commodity derivative assets with bank counterparties under our Credit Facility. The estimated fair value of commodity derivative assets has been risk-adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) as of December 31, 2023 for the counterparty. The Company believes that the counterparty currently is an acceptable credit risk.

The Company, at times, may have cash in banks in excess of federally insured amounts.

(q) Income Taxes

The Company recognizes deferred income tax assets and liabilities for temporary differences resulting from NOL carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in tax laws or tax rates is recognized in income during the period such changes are enacted. Deferred income tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion, or all, of the deferred income tax assets will not be realized. On July 8, 2022, Pennsylvania enacted new tax laws that are effective January 1, 2023 on a prospective basis that reduce the state's corporate income tax rate. As a result of this tax law change together with changes in the Company's apportionment to Pennsylvania, the Company's net deferred income tax liability was reduced by $41 million with a corresponding income tax benefit during the year ended December 31, 2022.

Unrecognized tax benefits represent potential future tax obligations for uncertain tax positions taken on previously filed tax returns that may not ultimately be sustained. The Company recognizes interest expense related to unrecognized tax benefits in interest expense and fines and penalties for tax-related matters as income tax expense.

(r) Fair Value Measurements

The FASB ASC Topic 820, *Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., those measured at fair value in a business combination, the initial recognition of asset retirement obligations, and impairments of proved oil and gas properties and other long-lived assets). Fair value is the price that the Company estimates would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value hierarchy is used to prioritize inputs to valuation techniques used to estimate fair value. An asset or liability subject to the fair value requirements is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The highest priority (Level 1) is given to unadjusted, quoted market prices in active markets for identical assets or liabilities, and the lowest priority (Level 3) is given to unobservable inputs. Level 2 inputs are data, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. Instruments that are valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter commodity fixed price swaps. Valuation models used to measure fair value of these instruments consider various Level 2 inputs including (i) quoted forward prices for commodities, (ii) time value, (iii) quoted forward interest rates, (iv) current market prices and contractual prices for the underlying instruments, (v) risk of nonperformance by the Company and the counterparty, and (vi) other relevant economic measures.

(s) Reportable Segments and Geographic Information

Management has evaluated how the Company is organized and managed and has identified the following segments: (i) the exploration, development and production of natural gas, NGLs and oil; (ii) marketing and utilization of excess firm transportation capacity; and (iii) midstream services through the Company's equity method investment in Antero Midstream. See Note 17—Reportable Segments to the consolidated financial statements for more information.

All of the Company's assets are located in the United States and substantially all of its production revenues are attributable to customers located in the United States. However, some of the Company's production revenues are attributable to customers who then transport the Company's production to foreign countries for resale or consumption.

(t) Net Income (Loss) Per Common Share

Net income (loss) per common share—basic for each period is computed by dividing net income (loss) attributable to Antero by the basic weighted average number of shares outstanding during the period. Net income (loss) per common share—diluted for each period is computed after giving consideration to the potential dilution from (i) outstanding equity awards using the treasury stock method and (ii) shares of common stock issuable upon conversion of the 2026 Convertible Notes using the if-converted method. The Company includes restricted stock unit ("RSU") awards, performance share unit ("PSU") awards and stock options in the calculation of diluted weighted average shares outstanding based on the number of common shares that would be issuable if the end of the period was also the end of the performance period required for the vesting of the awards. During periods in which the Company incurs a net loss, diluted weighted average shares outstanding is equal to basic weighted average shares outstanding because the effects of all equity awards and the 2026 Convertible Notes are anti-dilutive.

The following is a reconciliation of the Company's income (loss) attributable to common stockholders for basic and diluted net income (loss) per common share (in thousands):

	Year Ended December 31,		
	2021	2022	2023
Net income (loss) attributable to Antero Resources Corporation—common shareholders	$ (186,899)	1,898,771	242,919
Add: Interest expense for 2026 Convertible Notes	—	3,369	1,955
Less: Tax-effect of interest expense for 2026 Convertible Notes	—	(724)	(425)
Net income (loss) attributable to Antero Resources Corporation—common shareholders and assumed conversions	$ (186,899)	1,901,416	244,449
Net income (loss) per common share—basic	$ (0.61)	6.18	0.81
Net income (loss) per common share—diluted	$ (0.61)	5.78	0.78
Weighted average common shares outstanding—basic	308,146	307,202	299,793
Weighted average common shares outstanding—diluted	308,146	329,223	311,597

The following is a reconciliation of the Company's basic weighted average shares outstanding to diluted weighted average shares outstanding during the periods presented (in thousands):

	Year Ended December 31,		
	2021	2022	2023
Basic weighted average number of common shares outstanding	308,146	307,202	299,793
Add: Dilutive effect of RSUs	—	3,341	1,379
Add: Dilutive effect of PSUs	—	2,005	989
Add: Dilutive effect of 2026 Convertible Notes	—	16,675	9,436
Diluted weighted average number of common shares outstanding	308,146	329,223	311,597
Weighted average number of outstanding securities excluded from calculation of diluted net income (loss) per common share [(1)]:			
RSUs	6,407	111	1,200
PSUs	2,832	101	199
Stock options	379	346	310
2026 Convertible Notes	18,778	—	—

(1) The potential dilutive effects of these awards were excluded from the computation of net income (loss) per common share—diluted because the inclusion of these awards would have been anti-dilutive.

(u) Treasury Stock and Share Retirement

Treasury stock purchases are recorded at cost. The Company retires treasury shares acquired through share repurchases and returns those shares to the status of authorized but unissued. When treasury shares are retired, the Company's policy is to allocate the excess of the repurchase price over the par value of shares acquired first to additional paid-in capital and then to retained earnings (accumulated deficit) thereafter. The portion allocable to additional paid-in capital is determined by applying a percentage, determined by dividing the number of shares to be retired by the number of shares outstanding, to the balance of additional paid-in capital as of retirement.

(v) Equity-Based Compensation

The Company recognizes compensation cost related to all equity-based awards in the financial statements based on their estimated grant date fair value. The Company is authorized to grant various types of equity-based compensation awards including stock options, stock appreciation rights, restricted stock awards, restricted share unit awards, performance share unit awards, dividend equivalent awards and other types of awards. The grant date fair values are determined based on the type of award and may utilize market prices on the date of grant, Black-Scholes option-pricing model, Monte Carlo simulations or other acceptable valuation methodologies, as appropriate for the type of equity-based award. Compensation cost is recognized ratably over the applicable vesting or service period. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. See Note 9—Equity-Based Compensation to the consolidated financial statements for more information regarding the Company's equity-based compensation.

(w) Recently Adopted or Issued Accounting Standards

Convertible Debt Instruments

In August 2020, the FASB issued ASU No. 2020-06, *Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*, ("ASU 2020-06") which eliminates the cash conversion model in ASC 470-20, *Debt with Conversion and Other Options*, that require separate accounting for conversion features, and instead, allows the debt instrument and conversion features to be accounted for as a single debt instrument. It is effective for interim and annual reporting periods beginning after December 31, 2021. The Company adopted the standard effective January 1, 2022 under the modified retrospective transition method, which impacts only the debt instruments outstanding on the adoption date.

Upon adoption of this new standard, the Company reclassified $24 million, net of deferred income taxes and equity issuance costs, from additional paid-in capital and increased long-term debt by $27 million, reduced deferred income tax liability by $6 million and reduced accumulated deficit by $3 million as of January 1, 2022. Additionally, annual interest expense for the 2026 Convertible Notes beginning January 1, 2022 is based on an effective interest rate of 4.9% as compared to 15.3% for the year ended December 31, 2021.

Income Taxes

In December 2019, the FASB issued ASU No. 2019-12, *Simplifying the Accounting for Income Taxes*. This ASU removes certain exceptions to the general principles in ASC 740, *Income Taxes* ("ASC 740") and also simplifies portions of ASC 740 by clarifying and amending existing guidance. It is effective for interim and annual reporting periods beginning after December 15, 2020. The Company adopted this ASU on January 1, 2021, and it did not have a material impact on the Company's consolidated financial statements.

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

Reportable Segments

In November 2023, the FASB issued ASU No. 2023-07, Improvements to Reportable Segment Disclosures ("ASU 2023-07"). ASU 2023-07 is intended to improve reportable segment disclosures primarily through enhanced disclosure of reportable segment expenses. This ASU is effective for annual reporting periods beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. ASU 2023-07 is required to be applied retrospectively to all prior periods presented in the financial statements. The Company is evaluating the impact that ASU 2023-07 will have on the consolidated financial statements and its plans for adoption, including the adoption date.

(3) Transactions

(a) Conveyance of Overriding Royalty Interest

On June 15, 2020, the Company announced the consummation of a transaction with an affiliate of Sixth Street Partners, LLC ("Sixth Street") relating to certain overriding royalty interests across the Company's existing asset base (the "ORRIs"). In connection with the transaction, the Company contributed the ORRIs to Martica and Sixth Street contributed $300 million in cash (subject to customary adjustments) and agreed to contribute up to an additional $102 million in cash if certain production thresholds attributable to the ORRIs were achieved in 2020 and 2021. The Company met these production thresholds and received the $102 million of additional contributions from Sixth Street during 2020 and 2021. All cash contributed by Sixth Street at the initial closing and received as part of these additional contributions was distributed to the Company.

The ORRIs include an overriding royalty interest of 1.25% of the Company's working interest in all of its operated proved developed properties in West Virginia and Ohio, subject to certain excluded wells (the "Initial PDP Override"), and an overriding royalty interest of 3.75% of the Company's working interest in all of its undeveloped properties in West Virginia and Ohio (the "Development Override"). Wells turned to sales after April 1, 2020 and prior to the later of (a) the date on which the Company turns to sales 2.2 million lateral feet (net to the Company's interest) of horizontal wells burdened by the Development Override or (b) the earlier of (i) April 1, 2023 or (ii) the date on which the Company turns to sales 3.82 million lateral feet (net to the Company's interest) of horizontal wells are subject to the Development Override. As of April 1, 2023, Sixth Street no longer had the right to participate in any new wells, and Martica reconveyed the Development Override to the Company, except for the portion relating to wells turned to sales prior to April 1, 2023.

The ORRIs also include an additional overriding royalty interest of 2.00% of the Company's working interest in the properties underlying the Initial PDP Override (the "Incremental Override"). The Incremental Override (or a portion thereof, as applicable) may be re-conveyed to the Company (at the Company's election) if certain production targets attributable to the ORRIs are achieved through March 31, 2023. Any portion of the Incremental Override that may not be re-conveyed to the Company based on the Company failing to achieve such production volumes through March 31, 2023 will remain with Martica. As of March 31, 2023, 24% of the Incremental Override (or a 0.48% overriding royalty interest) will remain with Martica.

Prior to Sixth Street achieving an internal rate of return of 13% and 1.5x cash-on-cash return (the "Hurdle"), Sixth Street will receive all distributions in respect of the Initial PDP Override and the Development Override, and 24% of all distributions in respect of the Incremental Override, and the Company will receive 76% of all distributions in respect of the Incremental Override. Following Sixth Street achieving the Hurdle, the Company will receive 85% of the distributions in respect of the ORRIs to which Sixth Street was entitled immediately prior to the Hurdle being achieved.

(b) Drilling Partnership

On February 17, 2021, Antero Resources announced the formation of a drilling partnership with QL, an affiliate of Quantum Energy Partners, for the Company's 2021 through 2024 drilling program. Under the terms of the arrangement, each year in which QL participates represents an annual tranche, and QL will be conveyed a working interest in any wells spud by Antero Resources during such tranche year. For 2021 through 2024, Antero Resources and QL agreed to the estimated IRR of the Company's capital budget for each annual tranche, and QL agreed to participate in all four annual tranches. Antero Resources develops and manages the drilling program associated with each tranche, including the selection of wells. Additionally, for each annual tranche, Antero Resources and QL will enter into assignments, bills of sale and conveyances pursuant to which QL will be conveyed a proportionate working interest percentage in each well spud in that year, which conveyances will not be subject to any reversion.

Under the terms of the arrangement, QL funded development capital of 20%, 15% and 15% for wells spud in 2021, 2022 and 2023, respectively, and will fund 20% of development capital for wells spud in 2024, which funding amounts represent QL's proportionate working interest in such wells. Additionally, Antero Resources may receive a carry in the form of a one-time payment from QL for each annual tranche if the IRR for such tranche exceeds certain specified returns, which will be determined no earlier than October 31 and no later than December 1 following the end of each tranche year. The Company received a carry of $29 million for each of the 2021 and 2022 tranches during the years ended December 31, 2022 and 2023. All of the wells spud during each calendar year period will be a separate annual tranche. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche will be for Antero Resources' account. Subject to the preceding sentence, for any wells included in a tranche, QL is obligated and responsible for its working interest share of costs and liabilities, and is entitled to its working interest share of revenues, associated with such wells for the life of such wells.

The Company has accounted for the drilling partnership as a conveyance under ASC 932 and such conveyances are recorded in the consolidated financial statements as QL obtains its proportionate working interest in each well. No gain or loss was recognized for the interests conveyed during the years ended December 31, 2021, 2022 and 2023.

(4) Revenue

(a) Disaggregation of Revenue

The table set forth below presents revenue disaggregated by type and reportable segment to which it relates (in thousands). See Note 17—Reportable Segments to the consolidated financial statements for more information on reportable segments.

	Year Ended December 31,			
	2021	2022	2023	Reportable Segment
Revenues from contracts with customers:				
Natural gas sales	$ 3,442,028	5,520,419	2,192,349	Exploration and production
Natural gas liquids sales (ethane)	206,889	384,079	250,116	Exploration and production
Natural gas liquids sales (C3+ NGLs)	1,940,610	2,114,578	1,586,834	Exploration and production
Oil sales	201,232	275,673	247,146	Exploration and production
Marketing	718,921	416,758	206,122	Marketing
Other revenue	—	—	633	Exploration and production
Total revenue from contracts with customers	6,509,680	8,711,507	4,483,200	
Income (loss) from derivatives, deferred revenue and other sources, net	(1,890,248)	(1,573,071)	198,772	
Total revenue	$ 4,619,432	7,138,436	4,681,972	

(b) Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that have a contract term greater than one year, the Company utilized the practical expedient in ASC 606, *Revenue from Contracts with Customers* ("ASC 606"), which does not require the disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's product sales contracts, each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. For the Company's product sales that have a contract term of one year or less, the Company utilized the practical expedient in ASC 606, which does not require the disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

(c) Contract Balances

Under the Company's sales contracts, the Company invoices customers after its performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities. As of December 31, 2022 and 2023, the Company's receivables from contracts with customers were $708 million and $401 million, respectively.

(5) Equity Method Investment

(a) Summary of Equity Method Investment

As of December 31, 2022 and 2023, Antero owned 29.1% and 29.0%, respectively, of Antero Midstream's common stock, which is reflected in Antero's consolidated financial statements using the equity method of accounting.

The following table sets forth a reconciliation of Antero's investment in unconsolidated affiliate (in thousands):

Balance as of December 31, 2021 (1)	$ 232,399
Equity in earnings of unconsolidated affiliate	72,327
Dividends from unconsolidated affiliate	(125,138)
Elimination of intercompany profit	40,841
Balance as of December 31, 2022 (1)	220,429
Equity in earnings of unconsolidated affiliate	82,952
Dividends from unconsolidated affiliate	(125,138)
Elimination of intercompany profit	44,012
Balance as of December 31, 2023 (1)	$ 222,255

(1) The fair value of the Company's investment in Antero Midstream as of December 31, 2022 and 2023 was $1.5 billion and $1.7 billion, respectively, based on the quoted market share price of Antero Midstream.

(b) Summarized Financial Information of Antero Midstream

The tables set forth below present summarized financial information of Antero Midstream (in thousands):

Balance Sheet

	December 31,	
	2022	2023
Current assets	$ 88,993	91,128
Noncurrent assets	5,702,327	5,646,490
Total assets	$ 5,791,320	5,737,618
Current liabilities	$ 102,077	96,417
Noncurrent liabilities	3,496,925	3,489,470
Stockholders' equity	2,192,318	2,151,731
Total liabilities and stockholders' equity	$ 5,791,320	5,737,618

Statement of Operations

	Year Ended December 31,		
	2021	2022	2023
Revenues	$ 898,202	919,985	1,041,771
Operating expenses	342,875	380,519	429,909
Income from operations	555,327	539,466	611,862
Net income	$ 331,617	326,242	371,786

(6) Accrued Liabilities

Accrued liabilities consisted of the following items (in thousands):

	December 31, 2022	December 31, 2023
Capital expenditures	$ 57,361	38,848
Gathering, compression, processing and transportation expenses	162,783	160,758
Marketing expenses	61,118	36,428
Interest expense, net	31,892	33,066
Production and ad valorem taxes	32,536	51,516
General and administrative expense	32,477	35,641
Derivative settlements payable	53,732	1,037
Other	29,889	24,046
Total accrued liabilities	$ 461,788	381,340

(7) Long-Term Debt

Long-term debt consisted of the following items (in thousands):

	December 31, 2022	December 31, 2023
Credit Facility [a]	$ 34,800	417,200
8.375% senior notes due 2026 [e]	96,870	96,870
7.625% senior notes due 2029 [f]	407,115	407,115
5.375% senior notes due 2030 [g]	600,000	600,000
4.25% convertible senior notes due 2026 [h]	56,932	26,386
Total principal	1,195,717	1,547,571
Unamortized debt issuance costs	(12,241)	(9,975)
Long-term debt	$ 1,183,476	1,537,596

(a) Senior Secured Revolving Credit Facility

Antero Resources has a senior secured revolving credit facility with a consortium of bank lenders. On October 26, 2021, Antero Resources entered into an amended and restated Credit Facility. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of Antero Resources' assets and are subject to regular semi-annual redeterminations. As of December 31, 2022 and 2023, the Credit Facility had a borrowing base of $3.5 billion with lender commitments of $1.5 billion and $1.6 billion, respectively. The borrowing base was re-affirmed in the semi-annual redetermination in October 2023 and the next redetermination of the borrowing base is scheduled to occur in April 2024. The maturity date of the Credit Facility is the earlier of (i) October 26, 2026 and (ii) the date that is 180 days prior to the earliest stated redemption date of any series of the Company's then outstanding Senior Notes. As of December 31, 2023, the Credit Facility had an available borrowing capacity of $692 million.

The Credit Facility contains requirements with respect to leverage and current ratios, and certain covenants, including restrictions on our ability to incur debt and limitations on our ability to pay dividends unless certain customary conditions are met, in each case, subject to customary carve-outs and exceptions. Antero Resources was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2022 and 2023.

The Credit Facility in effect prior to October 26, 2021 provided for borrowing under either an Alternate Base Rate or as a Eurodollar Loan (as each term is defined in the agreement), and the Credit Facility in effect on and after October 26, 2021 provides for borrowing at either an Adjusted Term SOFR, an Adjusted Daily Simple SOFR or an Alternate Base Rate (each as defined in the Credit Facility). The Credit Facility provides for interest only payments until maturity at which time all outstanding borrowings are due. Interest was payable at a variable rate based on LIBOR or the Alternative Base Rate (as defined in the agreement), determined by election at the time of borrowing, plus an applicable margin rate under the Credit Facility in effect prior to October 26, 2021. Interest is payable at a variable rate based on SOFR or the Alternate Base Rate, determined by election at the time of borrowing, plus an applicable margin rate under the Credit Facility on or after October 26, 2021. Interest at the time of borrowing is determined with reference to the Antero Resources' then-current leverage ratio subject to certain exceptions. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from 0.375% to 0.500% with respect to the Credit Facility, determined with reference to borrowing base utilization subject to certain exceptions based on the leverage ratio then in effect. The Credit Facility includes fall away covenants, lower interest rates and reduced collateral requirements that Antero Resources may elect if Antero Resources is assigned an Investment Grade Rating (as defined in the Credit Facility).

As of December 31, 2022, Antero Resources had an outstanding balance under the Credit Facility of $35 million, with a weighted average interest rate of 6.42%, and outstanding letters of credit of $504 million. As of December 31, 2023, Antero Resources had an outstanding balance under the Credit Facility of $417 million, with a weighted average interest rate of 7.71%, and outstanding letters of credit of $501 million.

(b) 5.125% Senior Notes Due 2022

On May 6, 2014, Antero Resources issued $600 million of 5.125% senior notes due December 1, 2022 (the "2022 Notes") at par. On September 18, 2014, Antero Resources issued an additional $500 million of the 2022 Notes at 100.5% of par. The Company repurchased or otherwise fully redeemed all of the 2022 Notes between 2019 and the first quarter of 2021, and the 2022 Notes were fully retired as of February 10, 2021. Interest on the 2022 Notes was payable on June 1 and December 1 of each year. See "—Debt Repurchase Program" below for more information.

(c) 5.625% Senior Notes Due 2023

On March 17, 2015, Antero Resources issued $750 million of 5.625% senior notes due June 1, 2023 (the "2023 Notes") at par. The Company repurchased or otherwise fully redeemed all of the 2023 Notes between 2020 and the second quarter of 2021, and the 2023 Notes were fully retired as of June 1, 2021. Interest on the 2023 Notes was payable on June 1 and December 1 of each year. See "—Debt Repurchase Program" below for more information.

(d) 5.00% Senior Notes Due 2025

On December 21, 2016, Antero Resources issued $600 million of 5.00% senior notes due March 1, 2025 (the "2025 Notes") at par. The Company repurchased or otherwise redeemed all of the 2025 Notes between 2020 and the first quarter of 2022, and the 2025 Notes were fully retired as of March 1, 2022. Interest on the 2025 Notes was payable on March 1 and September 1 of each year. See "—Debt Repurchase Program" below for more information.

(e) 8.375% Senior Notes Due 2026

On January 4, 2021, Antero Resources issued $500 million of 8.375% senior notes due July 15, 2026 (the "2026 Notes") at par. The Company redeemed $175 million principal amount of the 2026 Notes on July 1, 2021 and redeemed or otherwise repurchased $228 million principal amount of the 2026 Notes during the year ended December 31, 2022, and as of December 31, 2023, $97 million principal amount of the 2026 Notes remained outstanding. See "—Debt Repurchase Program" below for more information. The 2026 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2026 Notes rank pari passu to Antero Resources' other outstanding Senior Notes. The 2026 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' existing subsidiaries that guarantee the Credit Facility and certain of its future restricted subsidiaries. Interest on the 2026 Notes is payable on January 15 and July 15 of each year. Antero Resources may redeem all or part of the 2026 Notes at any time on or after January 15, 2024 at redemption prices ranging from 104.188% on or after January 15, 2024 to 100.00% on or after January 15, 2026. At any time prior to January 15, 2024, Antero Resources may also redeem the 2026 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2026 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2026 Notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2026 Notes, plus accrued and unpaid interest.

(f) 7.625% Senior Notes Due 2029

On January 26, 2021, Antero Resources issued $700 million of 7.625% senior notes due February 1, 2029 (the "2029 Notes") at par. The Company redeemed or otherwise repurchased $116 million principal amount of the 2029 Notes during the year ended December 31, 2021 and repurchased $177 million of the 2029 Notes during the year ended December 31, 2022, and as of December 31, 2023, $407 million principal amount of the 2029 Notes remained outstanding. See "—Debt Repurchase Program" below for more information. The 2029 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2029 Notes rank pari passu to Antero Resources' other outstanding Senior Notes. The 2029 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' existing subsidiaries that guarantee the Credit Facility and certain of its future restricted subsidiaries. Interest on the 2029 Notes is payable on February 1 and August 1 of each year. Antero Resources may redeem all or part of the 2029 Notes at any time on or after February 1, 2024 at redemption prices ranging from 103.813% on or after February 1, 2024 to 100.00% on or after February 1, 2027. In addition, on or before February 1, 2024, Antero Resources may redeem up to 35% of the aggregate principal amount of the 2029 Notes, but in an amount not greater than the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 107.625% of the principal amount of the 2029 Notes, plus accrued and unpaid interest, which option the Company partially exercised on October 18, 2021 with its notice to redeem $116 million aggregate principal amount of outstanding 2029 Notes. At any time prior to February 1, 2024, Antero Resources may also redeem the 2029 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2029 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2029 Notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2029 Notes, plus accrued and unpaid interest.

(g) 5.375% Senior Notes Due 2030

On June 1, 2021, Antero Resources issued $600 million of 5.375% senior notes due March 1, 2030 (the "2030 Notes") at par. The 2030 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2030 Notes rank pari passu to Antero Resources' other outstanding Senior Notes. The 2030 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' existing subsidiaries that guarantee the Credit Facility and certain of its future restricted subsidiaries. Interest on the 2030 Notes is payable on March 1 and September 1 of each year. Antero Resources may redeem all or part of the 2030 Notes at any time on or after March 1, 2025 at redemption prices ranging from 102.688% on or after March 1, 2025 to 100.00% on or after March 1, 2028. In addition, on or before March 1, 2025, Antero Resources may redeem up to 35% of the aggregate principal amount of the 2030 Notes, but in an amount not greater than the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375% of the principal amount of the 2030 Notes, plus accrued and unpaid interest. At any time prior to March 1, 2025, Antero Resources may also redeem the 2030 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2030 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2030 Notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2030 Notes, plus accrued and unpaid interest.

(h) 4.25% Convertible Senior Notes Due 2026

On August 21, 2020, Antero Resources issued $250 million in aggregate principal amount of 4.25% convertible senior notes due September 1, 2026 (the "2026 Convertible Notes"). On September 2, 2020, Antero Resources issued an additional $37.5 million of the 2026 Convertible Notes. Proceeds from the issuance of the 2026 Convertible Notes totaled $278.5 million, net of initial purchasers' fees and issuance cost of $9 million. The Company extinguished $206 million principal amount of the 2026 Convertible Notes in 2021. In addition, during 2022 and 2023, $55 million aggregate principal amount of the 2026 Convertible Notes were converted pursuant to their terms or induced into conversion by the Company. See "—Equitizations, Conversions and Inducements," for more information. As of December 31, 2023, $26 million principal amount of the 2026 Convertible Notes remained outstanding. The 2026 Convertible Notes were issued pursuant to an indenture and are senior, unsecured obligations of Antero Resources. The 2026 Convertible Notes bear interest at a fixed rate of 4.25% per annum, payable semi-annually in arrears on March 1 and September 1 of each year, commencing on March 1, 2021. Each capitalized term used in this subsection but not otherwise defined in this Annual Report on Form 10-K has the meaning as set forth in the indenture governing the 2026 Convertible Notes.

The initial conversion rate is 230.2026 shares of Antero Resources' common stock per $1,000 principal amount of 2026 Convertible Notes, subject to adjustment upon the occurrence of specified events. As of December 31, 2023, the if-converted value of the 2026 Convertible Notes was $138 million, which exceeded the principal amount of the 2026 Convertible Notes by $112 million. The 2026 Convertible Notes will mature on September 1, 2026, unless earlier repurchased, redeemed or converted. Before May 1, 2026, noteholders will have the right to convert their 2026 Convertible Notes only upon the occurrence of the following events:

- during any calendar quarter (and only during such calendar quarter) commencing after the calendar quarter ending on September 30, 2020, if the Last Reported Sale Price per share of Antero Resources' common stock exceeds 130% of the Conversion Price for each of at least 20 Trading Days (whether or not consecutive) during the 30 consecutive Trading

Days ending on, and including, the last Trading Day of the immediately preceding calendar quarter (the “Stock Price Condition”);

- during the five consecutive Business Days immediately after any 10 consecutive Trading Day period (such 10 consecutive Trading Day period, the “Measurement Period”) if the Trading Price per $1,000 principal amount of 2026 Convertible Notes, as determined following a request by a noteholder in accordance with the procedures set forth below, for each Trading Day of the Measurement Period was less than 98% of the product of the Last Reported Sales Price per share of common stock on such Trading Day and the conversion rate on such Trading Day;

- if Antero Resources calls any or all of the 2026 Convertible Notes for redemption, at any time prior to the close of business on the scheduled Trading Day immediately preceding the redemption date; or

- upon the occurrence of certain specified corporate events as set forth in the indenture governing the 2026 Convertible Notes.

From and after May 1, 2026, noteholders may convert their 2026 Convertible Notes at any time at their election until the close of business on the second scheduled Trading Day immediately before the maturity date.

Upon conversion, Antero Resources may satisfy its conversion obligation by paying and/or delivering, as the case may be, cash, shares of Antero Resources’ common stock or a combination of cash and shares of Antero Resources’ common stock, at Antero Resources’ election, in the manner and subject to the terms and conditions provided in the indenture governing the 2026 Convertible Notes. The 2026 Convertible Notes have met the Stock Price Condition allowing holders of the 2026 Convertible Notes to exercise their conversion right as of December 31, 2023.

The conversion rate is subject to adjustment under certain circumstances in accordance with the terms of the indenture governing the 2026 Convertible Notes. In addition, following certain corporate events, as described in the indenture governing the 2026 Convertible Notes, that occur prior to the maturity date, Antero Resources will increase the conversion rate for a holder who elects to convert its 2026 Convertible Notes in connection with such a corporate event.

If certain corporate events that constitute a Fundamental Change occur, then noteholders may require Antero Resources to repurchase their 2026 Convertible Notes at a cash repurchase price equal to the principal amount of the 2026 Convertible Notes to be repurchased, plus accrued and unpaid interest, if any, to, but excluding, the Fundamental Change Repurchase Date. The definition of Fundamental Change includes certain business combination transactions involving Antero Resources and certain de-listing events with respect to Antero Resources’ common stock.

Upon issuance, the Company separately accounted for the liability and equity components of the 2026 Convertible Notes. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the 2026 Convertible Notes and the estimated fair value of the liability component was recorded as a debt discount and was amortized to interest expense, together with debt issuance costs, over the term of the 2026 Convertible Notes using the effective interest method, with an effective interest rate of 15.3% per annum. As of the issuance date, the fair value of the 2026 Convertible Notes was estimated at $172 million, resulting in a debt discount at inception of $116 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the 2026 Convertible Notes issuance. This equity component was recorded, net of deferred income taxes and issuance costs, in additional paid-in capital within the consolidated balance sheet and statement of stockholders’ equity.

Transaction costs related to the 2026 Convertible Notes issuance were allocated to the liability and equity components based on their relative fair values. Issuance costs attributable to the liability component were recorded within debt issuance costs on the consolidated balance sheet and were amortized over the term of the 2026 Convertible Notes using the effective interest method. Issuance costs attributable to the equity component were recorded as a charge to additional paid-in capital within the consolidated balance sheet and statement of stockholders’ equity.

Effective January 1, 2022, the Company adopted ASU 2020-06 whereby the Company reclassified the equity component of the 2026 Convertible Notes outstanding on such date, net of deferred income taxes and equity issuance costs, from additional paid-in capital to long-term debt. See Note 2—Summary of Significant Accounting Policies to the consolidated financial statements.

The 2026 Convertible Notes consist of the following (in thousands):

	December 31,	
	2022	2023
Principal	$ 56,932	26,386
Less: unamortized debt issuance costs	(1,159)	(404)
Net carrying value	$ 55,773	25,982

Interest expense recognized on the 2026 Convertible Notes related to the stated interest rate, amortization of the debt discount and debt issuance costs totaled $11 million, $3 million and $2 million for the years ended December 31, 2021, 2022 and 2023, respectively.

Equitizations, Conversions and Inducements

Equitizations

On January 12, 2021, the Company completed a registered direct offering (the "January Share Offering") of an aggregate of 31.4 million shares of its common stock at a price of $6.35 per share to certain holders of the 2026 Convertible Notes. The Company used the proceeds from the January Share Offering and $63 million of borrowings under the Credit Facility to repurchase from such holders $150 million aggregate principal amount of the 2026 Convertible Notes in privately negotiated transactions (the "January Convertible Note Repurchase," and, collectively with the January Share Offering, the "January Equitization Transactions"). The 2026 Convertible Notes had a conversion rate of 230.2026 shares of the Company's common stock per $1,000 principal amount, and the January Equitization Transactions had the effect of increasing this conversion rate to 275.3525 shares of common stock per $1,000 principal amount. The Company accounted for this transaction as an inducement of the 2026 Convertible Notes, and as a result, the Company recorded a $39 million loss on convertible note equitization in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2021 for the consideration paid in excess of the original terms of the 2026 Convertible Notes. Additionally, the January Equitization Transactions resulted in a loss on early extinguishment of debt of $41 million in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2021.

On May 13, 2021, the Company completed a registered direct offering (the "May Share Offering") of an aggregate of 11.6 million shares of its common stock at a price of $11.01 per share to certain holders of the 2026 Convertible Notes. The Company used the proceeds from the May Share Offering and $26 million of borrowings under the Credit Facility to repurchase from such holders $56 million aggregate principal amount of the 2026 Convertible Notes in privately negotiated transactions (the "May Convertible Note Repurchase," and, collectively with the May Share Offering, the "May Equitization Transactions"). The 2026 Convertible Notes had a conversion rate of 230.2026 shares of the Company's common stock per $1,000 principal amount, and the May Equitization Transactions had the effect of increasing this conversion rate to 245.2802 shares of common stock per $1,000 principal amount. The Company accounted for this transaction as an inducement of the 2026 Convertible Notes, and as a result, the Company recorded a $12 million loss on convertible note equitization in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2021 for the consideration paid in excess of the original terms of the 2026 Convertible Notes. Additionally, the May Equitization Transactions resulted in a loss on early extinguishment of debt of $21 million in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2021.

Conversions and Inducements

During the year ended December 31, 2022, $20 million aggregate principal amount of the 2026 Convertible Notes were converted pursuant to their terms, and an additional $5 million aggregate principal amount of the 2026 Convertible Notes were induced into conversion by the Company. The Company elected to settle these conversions by issuing approximately 6 million shares of common stock to the noteholders together with a cash inducement premium of $0.2 million. During the year ended December 31, 2023, $9 million aggregate principal amount of the 2026 Convertible Notes were converted pursuant to their terms, and an additional $21 million aggregate principal amount of the 2026 Convertible Notes were induced into conversion by the Company. The Company elected to settle these conversions by issuing 7 million shares of common stock to the noteholders together with a cash inducement premium of $0.4 million.

(i) Debt Repurchase Program

During the year ended December 31, 2021, the Company redeemed or repurchased through open market transactions (i) the remaining $661 million aggregate principal amount of its 2022 Notes at par, plus accrued and unpaid interest, (ii) the remaining $574 million aggregate principal amount of the 2023 Notes at par, plus accrued and unpaid interest, (iii) $5 million aggregate principal amount of its 2025 Notes at a weighted average redemption price of 102% of the principal amount thereof, plus accrued and unpaid interest, (iv) $175 million aggregate principal amount of its 2026 Notes at a redemption price of 108.375% of the principal amount thereof, plus accrued and unpaid interest and (v) $116 million aggregate principal amount of its 2029 Notes at a redemption price of 107.625% of the principal amount thereof, plus accrued and unpaid interest. For such redemptions and repurchases, the Company recognized a $31 million loss on early extinguishment of debt.

During the year ended December 31, 2022, the Company redeemed or repurchased through its previously disclosed tender offer and open market transactions (i) the remaining $585 million aggregate principal amount of its 2025 Notes at a redemption price of 101.25% of the principal amount thereof, plus accrued and unpaid interest, (ii) $228 million aggregate principal amount of its 2026 Notes at a weighted average redemption price of 109% of the principal amount thereof, plus accrued and unpaid interest and (iii) $177 million aggregate principal amount of its 2029 Notes at a weighted average redemption price of 106% of the principal amount thereof, plus accrued and unpaid interest. For such redemptions and repurchases, the Company recognized a $46 million loss on early extinguishment of debt.

There were no debt redemptions or repurchases during the year ended December 31, 2023.

(8) Asset Retirement Obligations

The following table presents a reconciliation of the Company's asset retirement obligations (in thousands):

	Year Ended December 31,	
	2022	2023
Beginning balance	$ 53,952	59,485
Obligations incurred	3,456	1,106
Accretion expense	4,906	3,244
Settlement of obligations	(1,050)	(718)
Obligations on sold properties	(42)	—
Revisions to prior estimates	(1,737)	(3,903)
Ending balance	$ 59,485	59,214

Revisions to prior estimates during the years ended December 31, 2022 and 2023 are primarily due to increases in estimated well lives. Asset retirement obligations are included in Other liabilities on the Company's consolidated balance sheets.

(9) Equity-Based Compensation

On June 17, 2020, Antero Resources' stockholders approved the Antero Resources Corporation 2020 Long-Term Incentive Plan (the "2020 Plan"), which replaced the Antero Resources Corporation Long-Term Incentive Plan (the "2013 Plan"), and the 2020 Plan became effective as of such date. The 2020 Plan provides for grants of stock options (including incentive stock options), stock appreciation rights, restricted stock awards, RSU awards, vested stock awards, dividend equivalent awards and other stock-based and cash awards. The terms and conditions of the awards granted are established by the Compensation Committee of Antero Resources' Board of Directors. Employees, officers, non-employee directors and other service providers of the Company and its affiliates are eligible to receive awards under the 2020 Plan. No further awards will be granted under the 2013 Plan on or after June 17, 2020.

The 2020 Plan provides for the reservation of 10,050,000 shares of the Company's common stock, plus the number of certain shares that become available again for delivery from the 2013 Plan in accordance with the share recycling provisions described below. The share recycling provisions allow for all or any portion of an award (including an award granted under the 2013 Plan that was outstanding as of June 17, 2020) that expires or is cancelled, forfeited, exchanged, settled for cash or otherwise terminated without actual delivery of the shares to be considered not delivered and thus available for new awards under the 2020 Plan. Further, any shares withheld or surrendered in payment of any taxes relating to awards that were outstanding under either the 2013 Plan as of June 17, 2020 or are granted under the 2020 Plan (other than stock options and stock appreciation rights), will again be available for new awards under the 2020 Plan.

A total of 7,059,518 shares were available for future grant under the 2020 Plan as of December 31, 2023.

Antero Midstream Partners' general partner was authorized to grant up to 10,000,000 common units representing limited partner interests in Antero Midstream Partners under the Antero Midstream Partners LP Long-Term Incentive Plan (the "AMP Plan") to non-employee directors of its general partner and certain officers, employees, and consultants of Antero Midstream Partners and its affiliates (which includes Antero Resources). Antero Resources deconsolidated Antero Midstream Partners on March 12, 2019, and on such date, each outstanding phantom unit award under the AMP Plan, was assumed by Antero Midstream and converted into 1.8926 RSUs (all such RSUs, the "Converted AM RSU Awards") under the Antero Midstream Corporation Long Term Incentive Plan (the "AM Plan"). Each RSU award under the AM Plan represented a right to receive one share of Antero Midstream common stock. As of December 31, 2023, all Converted AM RSU Awards were fully vested.

The Company's equity-based compensation expense, by type of award, is as follows (in thousands):

	Year Ended December 31,		
	2021	2022	2023
RSU awards	$ 13,232	18,915	32,744
PSU awards	4,662	14,920	25,322
Converted AM RSU Awards (1)	1,160	209	1
Equity awards issued to directors	1,383	1,399	1,452
Total expense	$ 20,437	35,443	59,519

(1) Antero Resources recognized compensation expense for equity awards granted under both the 2013 Plan and the AMP Plan because the awards under the AMP Plan are accounted for as if they are distributed by Antero Midstream Partners to Antero Resources. Antero Resources allocates a portion of equity-based compensation expense related to grants prior March 13, 2019 (date of deconsolidation) to Antero Midstream Partners based on its proportionate share of Antero Resources' labor costs. As of December 31, 2023, all Converted AM RSU Awards were fully vested, and there is no remaining unamortized expense attributable to these awards

The total fair value of the Company's vested equity awards for the years ended December 31, 2021, 2022 and 2023 were $34 million, $158 million and $75 million, respectively.

(a) Restricted Stock Unit Awards

RSU awards vest subject to the satisfaction of service requirements. Expense related to each RSU award is recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. The grant date fair values of these awards are determined based on the closing price of Antero Resources' common stock on the date of the grant. The weighted average grant date fair value per share for RSUs granted during the years ended December 31, 2021, 2022 and 2023 were $9.63, $35.64 and $25.90, respectively.

A summary of RSU award activity is as follows:

	Number of Units	Weighted Average Grant Date Fair Value
Total awarded and unvested—December 31, 2022	4,676,219	$ 15.29
Granted	1,474,930	25.90
Vested	(2,464,072)	10.92
Forfeited	(166,027)	23.83
Total awarded and unvested—December 31, 2023	3,521,050	$ 22.40

As of December 31, 2023, there was $57 million of unamortized equity-based compensation expense related to unvested RSUs. That expense is expected to be recognized over a weighted average period of 1.8 years.

(b) Performance Share Unit Awards

Performance Share Unit Awards Based on Total Shareholder Return

In 2018, the Company granted PSUs to certain of its employees and executive officers, a portion of which would vest based on the Company's absolute TSR, with target payout achieved if the price per share of Antero Resources' common stock reaches 125% of the beginning price (as defined in the award agreement) at the end of a three-year performance period ("2018 TSR PSUs"). The number of awards actually earned with respect to the 2018 TSR PSUs were subject to further adjustment based on the TSR of Antero Resources' common stock relative to the TSR of a peer group of companies over the same period. The number of shares of common stock that could ultimately be earned with respect to the 2018 TSR PSUs ranged from zero to 200% of the target number of 2018 TSR PSUs originally granted. Expense related to the 2018 TSR PSUs was recognized on a straight-line basis over three years. Forfeitures were accounted for as they occurred by reversing the expense previously recognized for awards that were forfeited during the period. The performance conditions for the 2018 TSR PSUs were not met, and no vesting for these awards was achieved.

In 2019, the Company granted PSUs to certain of its employees and executive officers that vested based on Antero Resources' absolute TSR, with target payout achieved if the price per share of Antero Resources' common stock reaches 125% of the beginning price (as defined in the award agreement) at the end of a three-year performance period ("2019 Absolute TSR PSUs"). The number of shares of common stock which could ultimately be earned ranged from zero to 200% of the PSUs granted. Expense related to these PSUs was recognized on a straight-line basis over three years. Forfeitures were accounted for as they occurred by reversing the expense previously recognized for awards that were forfeited during the period. During 2022, the market-based performance condition for the 2019 Absolute TSR PSUs was met at 200% of target and were converted into approximately 2 million shares of common stock.

In 2020, the Company granted PSU awards to certain of its executive officers that vested based on Antero Resources' absolute TSR determined as of the last day of each of three one-year performance periods ending on April 15, 2021, April 15, 2022 and April 15, 2023, and one cumulative three-year performance period ending on April 15, 2023, in each case, subject to the executive officer's continued employment through April 15, 2023 ("2020 Absolute TSR PSUs"). The number of shares of common stock that could ultimately be earned following the end of the cumulative three-year performance period ranged from zero to 150% of the target number of PSUs granted. Expense related to these PSUs was recognized on a graded-vested basis over approximately three years. Forfeitures were accounted for as they occurred by reversing the expense previously recognized for awards that were forfeited during the period. The performance conditions for each of the performance periods ended April 15, 2021, 2022 and 2023 were met. During 2023, the 2020 Absolute TSR PSUs vested at 112% of target for all four performance periods and were converted into approximately 0.2 million shares of common stock.

Additionally, in 2020, the Company granted PSUs to certain of its executive officers that vested based on Antero Resources' TSR relative to the TSR of certain peer companies determined as of the last day of each of three one-year performance periods ending on April 15, 2021, April 15, 2022, and April 15, 2023, and one cumulative three-year performance period ending on April 15, 2023, in each case, subject to the executive officer's continued employment through April 15, 2023 ("2020 Relative TSR PSUs"). The number of shares of common stock that could ultimately be earned following the end of the cumulative three-year performance period ranged from zero to 150% of the target number of PSUs granted. Expense related to these PSUs was recognized on a graded-vested basis over approximately three years. Forfeitures were accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. The performance condition for each of the performance periods ended April 15, 2021, 2022 and 2023 were met. During 2023, the 2020 Relative TSR PSUs vested at 126% of target for all four performance periods and were converted into approximately 0.2 million shares of common stock.

In 2021, the Company granted PSU awards to certain of its executive officers that vest based on Antero Resources' absolute TSR determined as of the last day of each of three one-year performance periods ending on April 15, 2022, April 15, 2023, and April 15, 2024, and one cumulative three-year performance period ending on April 15, 2024, in each case, subject to the executive officer's continued employment through April 15, 2024 ("2021 Absolute TSR PSUs"). The number of shares of common stock that may ultimately be earned following the end of the cumulative three-year performance period with respect to the 2021 Absolute TSR PSUs ranges from zero to 200% of the target number of 2021 Absolute TSR PSUs originally granted. Expense related to these PSUs is recognized on a graded-vested basis over the term of each performance period. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. The performance condition for the performance period ended April 15, 2022 was met, and 200% vesting was achieved for this award tranche. The performance condition for the performance period ended April 15, 2023 was not met, and as a result, no vesting for this award tranche was achieved.

In 2022, the Company granted PSU awards to certain of its senior management and executive officers that vest based on Antero Resources' absolute TSR determined as of the last day of each of three one-year performance periods ending on April 15, 2023, April 15, 2024 and April 15, 2025, and one cumulative three-year performance period ending on April 15, 2025, in each case, subject to certain continued employment criteria ("2022 Absolute TSR PSUs"). The number of shares of common stock that may ultimately be earned following the end of the cumulative three-year performance period with respect to the 2022 Absolute TSR PSUs ranges from zero to 200% of the target number of 2022 Absolute TSR PSUs originally granted. Expense related to these PSUs is recognized on a graded-vested basis over the term of each performance period. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. The performance condition for the performance period ended April 15, 2023 was not met, and as a result, no vesting for this award tranche was achieved.

Additionally, in 2022, the Company granted PSU awards to certain of its senior management and executive officers that vest based on Antero Resources' absolute TSR determined as of the last day of each of three one-year performance periods ending on December 31, 2023, December 31, 2024 and December 31, 2025, and one cumulative three-year performance period ending on December 31, 2025, in each case, subject to certain continued employment criteria ("Special 2022 Absolute TSR PSUs"). The number of shares of common stock that may ultimately be earned following the end of the cumulative three-year performance period with respect to the Special 2022 Absolute TSR PSUs ranges from zero to 200% of the target number of Special 2022 Absolute TSR PSUs originally granted. Expense related to these PSUs is recognized on a graded-vested basis over the term of each performance period. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. The performance condition for the performance period ended December 31, 2023 was not met, and as a result, no vesting for this award tranche was achieved.

In 2023, the Company granted PSU awards to certain of its senior management and executive officers that vest based on Antero Resources' absolute TSR determined as of the last day of each of three one-year performance periods ending on March 7, 2024, March 7, 2025 and March 7, 2026, and one cumulative three-year performance period ending on March 7, 2026, in each case, subject to certain continued employment criteria ("2023 Absolute TSR PSUs"). The number of shares of common stock that may ultimately be earned following the end of the cumulative three-year performance period with respect to the 2023 Absolute TSR PSUs ranges from zero to 200% of the target number of 2023 Absolute TSR PSUs originally granted. Expense related to these PSUs is recognized on a graded-vested basis over the term of each performance period. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period.

Performance Share Unit Awards Based on Leverage Ratio

In 2021, the Company granted PSUs to certain of its executive officers that vested based on the Company's total debt less cash and cash equivalents divided by the Company's Adjusted EBITDAX (as defined in the award agreement) determined as of the last day of each of three one-year performance periods ending on December 31, 2021, December 31, 2022, and December 31, 2023, in each case, subject to the executive officer's continued employment through December 31, 2023 ("2021 Leverage Ratio PSUs"). The number of shares of common stock that could ultimately be earned following the end of the third performance period with respect to the 2021 Leverage Ratio PSUs ranged from zero to 200% of the target number of 2021 Leverage Ratio PSUs originally granted. Expense related to the 2021 Leverage Ratio PSUs was recognized on a graded-vested basis over the term of each performance period that reflects the number of shares of common stock that are expected to be issued at the end of each measurement period, and such expense is reversed if the likelihood of achieving the performance condition becomes improbable. The performance conditions for the performance periods ended December 31, 2021, 2022 and 2023 were met at 200% of target. During the first quarter of 2024, the 2021 Leverage Ratio PSUs vested and converted into approximately 0.4 million shares of common stock.

In 2022, the Company granted PSUs to certain of its senior management and executive officers that vest based on the Company's total debt less cash and cash equivalents divided by the Company's Adjusted EBITDAX (as defined in the award agreement) determined as of the last day of each of three one-year performance periods ending on December 31, 2022, December 31, 2023 and December 31, 2024, in each case, subject to certain continued employment criteria ("2022 Leverage Ratio PSUs"). The number of shares of common stock that may ultimately be earned following the end of the third performance period with respect to the 2022 Leverage Ratio PSUs ranges from zero to 200% of the target number of 2022 Leverage Ratio PSUs originally granted. Expense related to the 2022 Leverage Ratio PSUs is recognized on a graded-vested basis over the term of each performance period that reflects the number of shares of common stock that are expected to be issued at the end of each measurement period, and such expense is reversed if the likelihood of achieving the performance condition becomes improbable. The performance conditions for the performance periods ended December 31, 2022 and 2023 were met, and 200% vesting was achieved for these award tranches. As of December 31, 2023, the likelihood of achieving the performance conditions related to the 2022 Leverage Ratio PSUs was probable.

Additionally, in 2022, the Company granted PSUs to certain of its senior management and executive officers that vest based on the Company's total debt less cash and cash equivalents divided by the Company's Adjusted EBITDAX (as defined in the award agreement) determined as of the last day of each of three one-year performance periods ending on December 31, 2023, December 31, 2024 and December 31, 2025, in each case, subject to certain continued employment criteria ("Special 2022 Leverage Ratio PSUs"). The number of shares of common stock that may ultimately be earned following the end of the third performance period with respect to the Special 2022 Leverage Ratio PSUs ranges from zero to 200% of the target number of Special 2022 Leverage Ratio PSUs originally granted. Expense related to the Special 2022 Leverage Ratio PSUs is recognized on a graded-vested basis over the term of each performance period that reflects the number of shares of common stock that are expected to be issued at the end of each measurement period, and such expense is reversed if the likelihood of achieving the performance condition becomes improbable. The performance condition for the performance period ended December 31, 2023 was met, and 200% vesting was achieved for this award tranche. As of December 31, 2023, the likelihood of achieving the performance conditions related to the Special 2022 Leverage Ratio PSUs was probable.

In 2023, the Company granted PSUs to certain of its senior management and executive officers that vest based on the Company's total debt less cash and cash equivalents divided by the Company's Adjusted EBITDAX (as defined in the award agreement) determined as of the last day of each of three one-year performance periods ending on December 31, 2023, December 31, 2024 and December 31, 2025, in each case, subject to certain continued employment criteria ("2023 Leverage Ratio PSUs"). The number of shares of common stock that may ultimately be earned following the end of the third performance period with respect to the 2023 Leverage Ratio PSUs ranges from zero to 200% of the target number of 2023 Leverage Ratio PSUs originally granted. Expense related to the 2023 Leverage Ratio PSUs is recognized on a graded-vested basis over the term of each performance period that reflects the number of shares of common stock that are expected to be issued at the end of each measurement period, and such expense is reversed if the likelihood of achieving the performance condition becomes improbable. The performance condition for the performance period ended December 31, 2023 was met, and 200% vesting was achieved for this award tranche. As of December 31, 2023, the likelihood of achieving the performance conditions related to the 2023 Leverage Ratio PSUs was probable.

Summary Information for Performance Share Unit Awards

A summary of PSU activity is as follows:

	Number of Units	Weighted Average Grant Date Fair Value
Total awarded and unvested—December 31, 2022	1,329,725	$ 23.18
Granted	417,466	28.51
Vested [(1)]	(335,000)	2.97
Total awarded and unvested—December 31, 2023	1,412,191	$ 29.54

(1) During the year ended December 31, 2023, the PSUs granted in 2020 that were based on absolute TSR and relative TSR met the performance criteria to achieve vesting at 112% and 126% of target, respectively, and converted into approximately 0.4 million shares of the Company's common stock.

The grant-date fair values of market-based PSUs were determined using Monte Carlo simulations, which use a probabilistic approach for estimating the fair values of the awards. Expected volatilities were derived from the volatility of the historical stock prices of a peer group of similar publicly-traded companies. The risk-free interest rate was determined using the yield available for zero-coupon U.S. government issues with remaining terms corresponding to the service periods of the PSUs. A dividend yield of zero was assumed. The grant-date fair value for the Adjusted EBITDAX-based PSUs was based on the closing price of Antero Resources' common stock on the date of the grant, assuming target achievement of the performance condition. The weighted average grant date fair value per share for PSUs granted during the years ended December 31, 2021, 2022 and 2023 were $9.71, $37.96 and $28.51, respectively.

The following table presents information regarding the weighted average fair values for market-based PSUs, and the assumptions used to determine the fair values:

	Year Ended December 31,		
	2021	2022	2023
Dividend yield	— %	— %	— %
Volatility	85 %	87 - 88 %	82 %
Risk-free interest rate	0.32 %	2.65 - 4.49 %	4.61 %
Weighted average fair value of awards granted	$ 11.99	49.32	33.96

As of December 31, 2023, there was $19 million of unamortized equity-based compensation expense related to unvested PSUs. That expense is expected to be recognized over a weighted average period of 1.5 years.

(c) Converted AM RSU Awards

Phantom units granted by Antero Midstream Partners vested subject to the satisfaction of service requirements, upon the completion of which common units in Antero Midstream Partners were delivered to the holder of the phantom units. Phantom units also contained distribution equivalent rights, which entitled the holder of vested common units to receive a "catch up" payment equal to common unit distributions paid by Antero Midstream Partners during the vesting period of the phantom unit award. These phantom units were treated, for accounting purposes, as if Antero Midstream Partners distributed the units to Antero Resources. Antero Resources recognized compensation expense as the units were granted to its employees, and a portion of the expense is allocated to Antero Midstream Partners. Expense related to each phantom unit award was recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures were accounted for as they occurred by reversing the expense previously recognized for awards that were forfeited during the period. The grant date fair values of these awards were determined based on the closing price of Antero Midstream Partners' common units on the date of grant.

On March 12, 2019, the Board of Directors of Antero Midstream adopted the AM Plan, and as a result, each outstanding phantom unit under the AMP Plan was assumed by Antero Midstream and converted into 1.8926 restricted stock units under the AM Plan.

A summary of the Converted AM RSU Awards is as follows:

	Number of Units	Weighted Average Grant Date Fair Value
Total awarded and unvested—December 31, 2022	2,827	$ 12.38
Vested	(2,827)	12.38
Total awarded and unvested—December 31, 2023	—	$ —

As of December 31, 2023, all Converted AM RSU Awards were fully vested resulting in no unamortized equity-based compensation expense related to unvested Converted AM RSU Awards.

(d) Stock Options

Stock options granted under the 2013 Plan have a maximum contractual life of 10 years. Expense related to stock options is recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. Stock options were granted with an exercise price equal to or greater than the market price of Antero Resources' common stock on the dates of grant.

A summary of stock option activity is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Intrinsic Value (in thousands) (1)
Outstanding—December 31, 2022	323,960	$ 50.86	2.0	$ —
Expired	(65,264)	54.10	—	—
Outstanding—December 31, 2023	258,696	$ 50.04	1.3	—
Vested—December 31, 2023	258,696	$ 50.04	1.3	$ —
Exercisable—December 31, 2023	258,696	$ 50.04	1.3	$ —

(1) Intrinsic values are based on the exercise price of the options and the closing price of Antero Resources' common stock on the referenced dates.

A Black-Scholes option-pricing model is used to determine the grant-date fair value of stock options. Expected volatility was derived from the volatility of the historical stock prices of a peer group of similar publicly traded companies' stock prices as Antero Resources' common stock had traded for a relatively short period of time at the dates the options were granted. The risk-free interest rate was determined using the implied yield available for zero-coupon U.S. government issues with a remaining term approximating the expected life of the options. A dividend yield of zero was assumed.

(10) Fair Value

The carrying values of accounts receivable and accounts payable as of December 31, 2022 and 2023 approximated market values because of their short-term nature. The carrying values of the amounts outstanding under the Credit Facility as of December 31, 2022 and 2023 approximated fair value because the variable interest rates are reflective of current market conditions.

The following table sets forth the fair value and carrying value of the Senior Notes and 2026 Convertible Notes (in thousands):

	December 31, 2022		December 31, 2023	
	Fair Value (1)	Carrying Value (2)	Fair Value (1)	Carrying Value (2)
2026 Notes	$ 100,987	96,123	99,534	96,351
2029 Notes	410,860	402,872	417,781	403,441
2030 Notes	556,260	593,908	573,720	594,622
2026 Convertible Notes	406,039	55,773	138,337	25,982
Total	$ 1,474,146	1,148,676	1,229,372	1,120,396

(1) Fair values are based on Level 2 market data inputs.
(2) Carrying values are presented net of unamortized debt issuance costs.

See Note 9—Equity-Based Compensation to the consolidated financial statements for information regarding the fair value of equity based awards. See Note 11—Derivative Instruments to the consolidated financial statements for information regarding the fair value of derivative financial instruments.

(11) Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations, and it may use derivative instruments to manage its commodity price risk. In addition, the Company periodically enters into contracts that contain embedded features that are required to be bifurcated and accounted for separately as derivatives.

(a) Commodity Derivative Positions

The Company periodically enters into natural gas, NGLs and oil derivative contracts with counterparties to hedge the price risk associated with its production. These derivatives are not entered into for trading purposes. To the extent that changes occur in the market prices of natural gas, NGLs and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas, NGLs and oil recognized upon the ultimate sale of the Company's production.

The Company was party to various fixed price commodity swap contracts that settled during the years ended December 31, 2021, 2022 and 2023. As of December 31, 2023, the Company has no fixed price commodity swap contracts. The Company enters into these swap contracts when management believes that favorable future sales prices for the Company's production can be secured. Under these swap agreements, when actual commodity prices upon settlement exceed the fixed price provided by the swap contracts, the Company pays the difference to the counterparty. When actual commodity prices upon settlement are less than the contractually provided fixed price, the Company receives the difference from the counterparty. In addition, the Company has entered into basis swap contracts in order to hedge the difference between the NYMEX index price and a local index price. Under these basis swap agreements, when actual commodity prices upon settlement exceed the fixed price provided by the swap contracts, the Company receives the difference from the counterparty. When actual commodity prices upon settlement are less than the contractually provided fixed price, the Company pays the difference to the counterparty.

The Company's derivative contracts have not been designated as hedges for accounting purposes; therefore, all gains and losses are recognized in the Company's statements of operations and comprehensive income (loss).

The Company has a call option and an embedded put option tied to NYMEX pricing for the production volumes associated with the Company's retained interest in the VPP properties. The put option was embedded within another contract, and since the embedded put option was not clearly and closely related to its host contract, the Company bifurcated this derivative instrument and reflects it at fair value in the consolidated financial statements. As of December 31, 2023, the Company's call option and embedded put option arrangements were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Call Option Strike Price	Embedded Put Option Strike Price
Natural Gas				
January-December 2024	Henry Hub	53,000 MMBtu/day	2.477 /MMBtu	2.527 /MMBtu
January-December 2025	Henry Hub	44,000 MMBtu/day	2.564 /MMBtu	2.614 /MMBtu
January-December 2026	Henry Hub	32,000 MMBtu/day	2.629 /MMBtu	2.679 /MMBtu

As of December 31, 2023, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of the Columbia Gas Transmission pipeline ("TCO") to the NYMEX Henry Hub natural gas price were as follows:

Commodity / Settlement Period	Index to Basis Differential	Contracted Volume	Weighted Average Hedged Differential
Natural Gas			
January-December 2024	NYMEX to TCO	50,000 MMBtu/day	0.530 /MMBtu

In addition, the Company had a swaption agreement, which entitled the counterparty the right, but not the obligation, to enter into a fixed price swap agreement on December 21, 2023 to purchase 427,500 MMBtu/d at a price of $2.77 per MMBtu for the year ending December 31, 2024. In 2023, the Company executed an early settlement of this swaption agreement and made a cash payment of $202 million.

As of December 31, 2023, the Company's fixed price swap positions for Martica, the Company's consolidated VIE, were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Weighted Average Price
Natural Gas			
January-December 2024	Henry Hub	23,885 MMBtu/day	2.33 /MMBtu
January-March 2025	Henry Hub	18,021 MMBtu/day	2.53 /MMBtu
Oil			
January-December 2024	West Texas Intermediate	43 Bbl/day	44.02 /Bbl
January-March 2025	West Texas Intermediate	39 Bbl/day	45.06 /Bbl

(b) Summary

The table below presents a summary of the fair values of the Company's derivative instruments and where such values are recorded in the consolidated balance sheets (in thousands):

	Balance Sheet Location	December 31, 2022	December 31, 2023
Asset derivatives not designated as hedges for accounting purposes:			
Embedded derivatives—current	Derivative instruments	$ 1,900	5,175
Embedded derivatives—noncurrent	Derivative instruments	9,844	5,570
Total asset derivatives (1)		11,744	10,745
Liability derivatives not designated as hedges for accounting purposes:			
Commodity derivatives—current (2)	Derivative instruments	97,765	15,236
Commodity derivatives—noncurrent (2)	Derivative instruments	345,280	32,764
Total liability derivatives (1)		443,045	48,000
Net derivatives liability (1)		$ (431,301)	(37,255)

(1) The fair value of derivative instruments was determined using Level 2 inputs.
(2) As of December 31, 2022, $47 million of commodity derivative liabilities, including $28 million of current commodity derivatives and $19 million of noncurrent commodity derivatives, are attributable to the Company's consolidated VIE, Martica. As of December 31, 2023, approximately $5 million of commodity derivative liabilities, including $3 million of current commodity derivatives and $2 million of noncurrent commodity derivatives, are attributable to the Company's consolidated VIE, Martica.

The following table sets forth the gross values of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets as of the dates presented, all at fair value (in thousands):

	December 31, 2022			December 31, 2023		
	Gross Amounts Recognized	Gross Amounts Offset Recognized	Net Amounts of Assets (Liabilities) on Balance Sheet	Gross Amounts Recognized	Gross Amounts Offset Recognized	Net Amounts of Assets (Liabilities) on Balance Sheet
Commodity derivative assets	$ 276	(276)	—	406	(406)	—
Embedded derivative assets	11,744	—	11,744	10,745	—	10,745
Commodity derivative liabilities	(443,321)	276	(443,045)	(48,406)	406	(48,000)

The following table sets forth a summary of derivative fair value gains and losses and where such values are recorded in the consolidated statements of operations and comprehensive income (loss) (in thousands):

	Statement of Operations Location	Year Ended December 31,		
		2021	2022	2023
Commodity derivative fair value gains (losses) [(1)]	Revenue	$ (1,886,551)	(1,524,250)	165,448
Embedded derivative fair value gains (losses) [(1)]	Revenue	(49,958)	(91,586)	876

(1) The fair value of derivative instruments was determined using Level 2 inputs.

Commodity derivative fair value gains (losses) for the years ended December 31, 2021 and 2023 include losses of $5 million and $202 million related to the settlement of certain natural gas derivatives prior to the contractual settlement dates. Payments for these early settlements are classified as operating cash flows on the Company's consolidated statement of cash flows for the years ended December 31, 2021 and 2023. There were no early settlements of commodity derivatives during the year ended December 31, 2022.

The Company's commodity derivative position presented in Note 11(a) above reflects the volume and adjusted fixed price indices after the 2021 and 2023 early settlements of certain natural gas derivatives.

(12) Leases

The Company leases certain office space, processing plants, drilling rigs and completion services, gas gathering lines, compressor stations, and other office and field equipment. Leases with an initial term of 12 months or less are considered short-term and are not recorded on the balance sheet. Instead, the short-term leases are recognized in expense on a straight-line basis over the lease term.

Most leases include one or more options to renew, with renewal terms that can extend the lease from one to 20 years or more. The exercise of the lease renewal options is at the Company's sole discretion. The depreciable lives of the leased assets are limited by the expected lease term, unless there is a transfer of title or purchase option reasonably certain of exercise.

Certain of the Company's lease agreements include minimum payments based on a percentage of produced volumes over contractual levels and others include rental payments adjusted periodically for inflation.

The Company considers all contracts that have assets specified in the contract, either explicitly or implicitly, that the Company has substantially all of the capacity of the asset, and has the right to obtain substantially all of the economic benefits of that asset, without the lessor's ability to have a substantive right to substitute that asset, as leased assets. For any contract deemed to include a leased asset, that asset is capitalized on the consolidated balance sheet as a right-of-use asset and a corresponding lease liability is recorded at the present value of the known future minimum payments of the contract using a discount rate on the date of commencement. The leased asset classification is determined at the date of recording as either operating or financing, depending upon certain criteria of the contract.

The discount rate used for present value calculations is the discount rate implicit in the contract. If an implicit rate is not determinable, a collateralized incremental borrowing rate is used at the date of commencement. As new leases commence or previous leases are modified the discount rate used in the present value calculation is the current period applicable discount rate.

The Company has made an accounting policy election to adopt the practical expedient for combining lease and non-lease components on an asset class basis. This expedient allows the Company to combine non-lease components such as real estate taxes, insurance, maintenance and other operating expenses associated with the leased premises with the lease component of a lease agreement on an asset class basis when the non-lease components of the agreement cannot be easily bifurcated from the lease payment. Currently, the Company is only applying this expedient to certain office space agreements.

(a) Supplemental Balance Sheet Information Related to Leases

The Company's lease assets and liabilities consisted of the following items (in thousands):

Leases	Balance Sheet Classification	December 31, 2022	December 31, 2023
Operating Leases			
Operating lease right-of-use assets:			
Processing plants	Operating lease right-of-use assets	$ 1,849,116	1,611,903
Drilling rigs and completion services	Operating lease right-of-use assets	85,405	32,187
Gas gathering lines and compressor stations [1]	Operating lease right-of-use assets	1,463,756	1,283,668
Office space	Operating lease right-of-use assets	41,822	37,706
Vehicles	Operating lease right-of-use assets	756	—
Other office and field equipment	Operating lease right-of-use assets	3,476	416
Total operating lease right-of-use assets		$ 3,444,331	2,965,880
Operating lease liabilities:			
Short-term operating lease liabilities	Short-term lease liabilities	$ 556,137	538,954
Long-term operating lease liabilities	Long-term lease liabilities	2,888,194	2,425,785
Total operating lease liabilities		$ 3,444,331	2,964,739
Finance Leases			
Finance lease right-of-use assets:			
Vehicles	Other property and equipment	$ 2,159	3,771
Total finance lease right-of-use assets [2]		$ 2,159	3,771
Finance lease liabilities:			
Short-term finance lease liabilities	Short-term lease liabilities	$ 499	1,106
Long-term finance lease liabilities	Long-term lease liabilities	1,660	2,665
Total finance lease liabilities		$ 2,159	3,771

(1) Gas gathering lines and compressor stations includes $1.4 billion and $1.3 billion related to Antero Midstream as of December 31, 2022 and 2023, respectively. See "—Related party lease disclosure" for additional discussion.
(2) Financing lease assets are recorded net of accumulated amortization of $1 million as of December 31, 2022 and 2023.

The processing plants, gathering lines and compressor stations that are classified as lease liabilities are classified as such under ASC 842, *Leases*, because Antero (i) is the sole customer of the assets and (ii) makes the decisions that most impact the economic performance of the assets.

(b) Supplemental Information Related to Leases

Costs associated with operating and finance leases were included in the consolidated financial statements as follows (in thousands):

Cost	Classification	Location	Year Ended December 31, 2021	2022	2023
Operating lease cost	Statement of operations	Gathering, compression, processing and transportation	$ 1,518,305	1,481,022	1,623,268
Operating lease cost	Statement of operations	General and administrative	10,901	11,472	12,121
Operating lease cost	Statement of operations	Contract termination	4,213	12,000	4,227
Operating lease cost	Statement of operations	Lease operating	142	177	84
Operating lease cost	Balance sheet	Proved properties (1)	103,741	123,756	160,638
Total operating lease cost . .			$ 1,637,302	1,628,427	1,800,338
Finance lease cost:					
Amortization of right-of-use assets	Statement of operations	Depletion, depreciation and amortization	$ 522	351	1,530
Interest on lease liabilities . .	Statement of operations	Interest expense	352	193	597
Total finance lease cost .			$ 874	544	2,127
Short-term lease payments			$ 86,039	141,470	137,781

(1) Capitalized costs related to drilling and completion activities.

(c) Supplemental Cash Flow Information Related to Leases

The following table presents the Company's supplemental cash flow information related to leases (in thousands):

	Year Ended December 31, 2021	2022	2023
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 1,352,941	1,380,968	1,366,677
Operating cash flows from finance leases	352	193	597
Investing cash flows from operating leases	88,910	103,244	126,483
Financing cash flows from finance leases	859	575	830
Noncash activities:			
Right-of-use assets obtained in exchange for new operating lease obligations	$ 437,045	366,194	76,797
Increase (decrease) to existing right-of-use assets and lease obligations from operating lease modifications, net (1)	$ 702,512	154,101	(15,858)

(1) During the year ended December 31, 2021, the weighted average discount rate for remeasured operating leases decreased from 14.4% as of December 31, 2020 to 5.0% as of December 31, 2021. During the year ended December 31, 2022, the weighted average discount rate for remeasured operating leases decreased from 5.6% as of December 31, 2021 to 5.2% as of December 31, 2022. During the year ended December 31, 2023, the weighted average discount rate for remeasured operating leases increased from 5.1% as of December 31, 2022 to 6.5% as of December 31, 2023.

(d) Maturities of Lease Liabilities

The table below is a schedule of future minimum payments for operating and financing lease liabilities as of December 31, 2022 (in thousands):

	Operating Leases	Financing Leases	Total
2024	$ 699,335	1,628	700,963
2025	608,160	1,585	609,745
2026	555,915	1,230	557,145
2027	457,782	197	457,979
2028	379,922	23	379,945
Thereafter	872,055	9	872,064
Total lease payments	3,573,169	4,672	3,577,841
Less: imputed interest	(608,430)	(901)	(609,331)
Total	$ 2,964,739	3,771	2,968,510

(e) Lease Term and Discount Rate

The following table sets forth the Company's weighted average remaining lease term and discount rate:

	December 31, 2022		December 31, 2023	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Weighted average remaining lease term	7.2 years	3.5 years	6.5 years	3.0 years
Weighted average discount rate	5.3 %	7.4 %	5.9 %	8.3 %

(f) Related Party Lease Disclosure

The Company has gathering and compression service agreements with Antero Midstream that include: (i) the second amended and restated gathering and compression agreement dated December 8, 2019 (the "2019 gathering and compression agreement"), (ii) a gathering and compression agreement from Antero Midstream's acquisition of certain Marcellus gathering and compression assets (the "Marcellus gathering and compression agreement") and (iii) a compression agreement from Antero Midstream's acquisition of certain Utica compressors (the "Utica compression agreement" and, together with the 2019 gathering and compression agreement and the Marcellus gathering and compression agreement, the "gathering and compression agreements"). Pursuant to the gathering and compression agreements with Antero Midstream, the Company has dedicated substantially all of its current and future acreage in West Virginia, Ohio and Pennsylvania to Antero Midstream for gathering and compression services. The 2019 gathering and compression agreement has an initial term through 2038, the Marcellus gathering and compression agreement expires in 2031 and the Utica compression agreement has two dedicated areas that expire in 2024 and 2030. Upon expiration of each of the Marcellus gathering and compression agreement and the Utica compression agreement, Antero Midstream will continue to provide gathering and compression services under the 2019 gathering and compression agreement.

Under the gathering and compression agreements, Antero Midstream receives a low pressure gathering fee per Mcf, a high pressure gathering fee per Mcf and a compression fee per Mcf, as applicable, subject to annual adjustments based on CPI. If and to the extent the Company requests that Antero Midstream construct new low pressure lines, high pressure lines and compressor stations, the 2019 gathering and compression agreement contains options at Antero Midstream's election for either (i) minimum volume commitments that require Antero Resources to utilize or pay for 75% of the high pressure gathering capacity and 70% of the compression capacity of the requested capacity of such new construction for 10 years or (ii) a cost of service fee that allows the Antero Midstream to earn a 13% rate of return on such new construction over seven years. In addition, the Marcellus gathering and compression agreement provides for a minimum volume commitment that requires the Company to utilize or pay for 25% of the compression capacity for a period of 10 years from the in-service date.

The 2019 gathering and compression agreement includes a growth incentive fee program whereby low pressure gathering fees were reduced during the years ended December 31, 2021, 2022 and 2023 to the extent the Company achieved certain quarterly volumetric targets. The Company's throughput gathered under the Marcellus gathering and compression assets acquired by Antero Midstream was not considered in low pressure gathering volume targets. Upon completion of the initial contract term, the 2019 gathering and compression agreement will continue in effect from year to year until such time as the agreement is terminated, effective upon an anniversary of the effective date of the agreement, by either the Company or Antero Midstream on or before the 180th day prior to the anniversary of such effective date. The Company earned fee rebates for the years ended December 31, 2021, 2022 and 2023 of $12 million, $48 million and $52 million, respectively. The growth incentive fee program expired on December 31, 2023.

For the years ended December 31, 2021, 2022 and 2023, gathering and compression fees paid by Antero related to these agreements were $705 million, $660 million and $738 million, respectively. As of December 31, 2022 and 2023, $59 million and $65 million, respectively was included within Accounts payable, related parties, on the consolidated balance sheets as due to Antero Midstream related to these agreements.

(13) Income Taxes

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

	Year Ended December 31,		
	2021	2022	2023
Current income tax expense	$ 216	847	1,587
Deferred income tax expense (benefit)	(74,293)	447,845	74,407
Total income tax expense (benefit)	$ (74,077)	448,692	75,994

Income tax expense (benefit) differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 21% to income or loss before taxes as a result of the following (in thousands):

	Year Ended December 31,		
	2021	2022	2023
Federal income tax expense (benefit)	$ (47,919)	519,679	87,746
State income tax expense (benefit), net of federal effect	(6,576)	12,461	3,512
Change in state tax rate, net of federal effect	(30,910)	(52,747)	11,417
Equity-based compensation	1,117	(9,717)	(772)
Dividends received deduction	(3,832)	(1,749)	(3,186)
Noncontrolling interests	(7,862)	(27,347)	(21,525)
Change in valuation allowance	4,606	7,070	(2,567)
Nondeductible loss on 2026 Convertible Notes equitizations and inducement	12,174	36	81
Other	5,125	1,006	1,288
Total income tax expense (benefit)	$ (74,077)	448,692	75,994

Deferred income taxes reflect the impact of temporary differences between assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. The tax effect of the temporary differences giving rise to deferred income tax assets and liabilities is as follows (in thousands):

	December 31, 2022	December 31, 2023
Deferred income tax assets:		
NOL carryforwards	$ 282,829	281,217
Interest expense carryforwards	—	25,258
Equity-based compensation	3,362	7,056
Investment in Antero Midstream	254,164	234,423
Unrealized losses on derivative instruments	83,269	51,025
Lease liabilities	740,254	644,622
Asset retirement obligations and other	15,859	17,093
Total deferred income tax assets	1,379,737	1,260,694
Valuation allowance	(57,375)	(54,805)
Deferred income tax assets, net	1,322,362	1,205,889
Deferred income tax liabilities:		
Oil and gas properties	1,295,847	1,338,442
Lease right-of-use assets	740,254	644,870
Investment in Martica	45,507	55,759
2026 Convertible Notes and other	615	1,086
Total deferred income tax liabilities	2,082,223	2,040,157
Deferred tax liability, net	$ (759,861)	(834,268)

In assessing the realizability of deferred income tax assets, management considers whether some portion or all of the deferred income tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which the Company's temporary differences become deductible. Management considers the scheduled reversal of deferred income tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the projections of future taxable income over the periods in which the deferred income tax assets are deductible, management believes that the Company will not realize the benefits of certain of these deductible differences and has recorded a valuation allowance of approximately $57 million and $55 million as of December 31, 2022 and 2023, respectively. The valuation allowance for each of the years ended December 31, 2022 and 2023, relates primarily to Colorado, Oklahoma and West Virginia state NOL carryforwards and are the result of expected future reduced income tax apportionment in those states. The amount of the deferred income tax asset considered realizable could be further reduced in the near term if estimates of future taxable income during the carryforward period are revised.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The Company has no unrecognized tax benefit balances through December 31, 2023.

As of December 31, 2023, the Company has U.S. federal and state NOL carryforwards of $1.0 billion and $1.9 billion, respectively, exclusive of the valuation allowances discussed above. The U.S. federal and West Virginia NOL carryforwards generated in tax years prior to 2018 expire between 2036 and 2037. For tax years 2018 and thereafter, U.S. federal and West Virginia NOL carryforwards generated in these jurisdictions have no expiration date. The Colorado NOL carryforwards generated in tax years prior to 2018 or in 2021 expire between 2025 and 2041. The Colorado NOL Carryforwards generated in tax years 2018 through 2020 have no expiration date.

Tax years 2020 through 2023 remain open to examination by the U.S. Internal Revenue Service. The Company and its subsidiaries file tax returns with various state taxing authorities and those returns remain open to examination for tax years 2019 through 2023.

(14) Commitments

The following table sets forth a schedule of future minimum payments for the Company's contractual obligations, which include leases that have a lease term in excess of one year as of December 31, 2023 (in thousands):

	Firm Transportation (a)	Processing, Gathering, Compression and Water Service (b)	Operating and Financing Leases (c)	Imputed Interest for Leases (c)	Other (d)	Total
2024	$ 1,171,743	67,201	540,101	160,862	8,412	1,948,319
2025	1,158,209	55,853	479,666	130,080	4,875	1,828,683
2026	1,155,797	22,676	455,118	102,027	2,250	1,737,868
2027	1,151,152	21,387	381,598	76,380	—	1,630,517
2028	1,095,015	20,054	324,786	55,159	—	1,495,014
Thereafter	4,382,740	77,753	787,241	84,823	—	5,332,557
Total	$ 10,114,656	264,924	2,968,510	609,331	15,537	13,972,958

(a) Firm Transportation

The Company has entered into firm transportation agreements with various pipelines in order to facilitate the delivery of its production to market. These contracts commit the Company to transport minimum daily natural gas or NGLs volumes at negotiated rates, or pay for any deficiencies at specified reservation fee rates. The amounts in this table are based on the Company's minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(b) Processing, Gathering, Compression and Water Service Commitments

The Company has entered into various long-term gas processing, gathering, compression and water service agreements. Certain of these agreements were determined to be leases. The minimum payment obligations under the agreements that are not leases are presented in this column.

The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(c) Operating and Finance Leases, including Imputed Interest

The Company has obligations under contracts for services provided by drilling rigs and completion fleets, processing, gathering, and compression services agreements, and office and equipment leases. The values in the table represent the gross amounts that Antero Resources is committed to pay; however, the Company will record in its financial statements its proportionate share of costs based on its working interests. See Note 12—Leases to the consolidated financial statements for more information on the Company's operating and finance leases.

(d) Other

The Company has entered into various land acquisition and sand supply agreements. Certain of these agreements contain minimum payment obligations over various terms. The values in the table represent the minimum payments due under these arrangements. None of these agreements were determined to be leases.

(e) Contract Terminations

The Company incurs costs associated with the delay or cancellation of certain contracts with third parties. These costs are recorded in contract termination and included in the statements of operations and comprehensive income (loss). During 2022, the Company cancelled the construction of the Smithburg 2 gas processing plant and made a cash payment of $12 million. During 2023, the Company executed an early termination of its firm transportation commitment of 200,000 MMBtu/d on the Equitrans pipeline and made a cash payment of $24 million. There are no remaining payment obligations related to any delayed or cancelled contracts as of December 31, 2023.

(15) Contingencies

Environmental

In June 2018, the Company received a Notice of Violation ("NOV") from the EPA Region III for alleged violations of the federal Clean Air Act and the West Virginia State Implementation Plan. The NOV alleges that combustion devices at these facilities did not meet applicable air permitting requirements. Separately, in June 2018, the Company received an information request from the EPA Region III pursuant to Section 114(a) of the Clean Air Act relating to the facilities that were inspected in September 2017 as well as additional Antero Resources facilities for the purpose of determining if the additional facilities have the same alleged compliance issues that were identified during the September 2017 inspections. Subsequently, the West Virginia Department of Environmental Protection ("WVDEP") and the EPA Region V (covering Ohio facilities) each conducted its own inspections, and the Company has separately received NOVs from WVDEP and EPA Region V related to similar issues being investigated by the EPA Region III. The Company continues to negotiate with the EPA and WVDEP to resolve the issues alleged in the NOVs and the information request. The Company's operations at these facilities are not suspended, and management does not expect these matters to have a material adverse effect on the Company's financial condition, results of operations or cash flows.

WGL

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively, "WGL") were involved in multiple contractual disputes involving firm gas sales contracts executed June 20, 2014 (the "Contracts") that the Company began delivering gas under in January 2016. In late 2015, WGL asserted that the natural gas index price specified in the Contracts was no longer appropriate and sought to invoke an alternative index clause in the Contracts. This dispute was referred to arbitration. In January 2017, the arbitration panel ruled in the Company's favor and found that the natural gas index price specified in the Contracts should remain.

In March of 2017, WGL filed a lawsuit against the Company in Colorado district court claiming that the Company breached contractual obligations by failing to deliver "TCO pool" gas, ultimately seeking damages of more than $40 million. Subsequently, after WGL failed to take certain volumes of gas required under the Contracts, the Company filed a separate lawsuit against WGL to recover damages that WGL refused to pay. These two lawsuits were consolidated and tried in June 2019. On June 20, 2019, the Company was awarded a jury verdict of approximately $96 million in damages against WGL. In addition, the jury rejected WGL's claim against the Company, finding that the Company did not breach the Contracts. On December 10, 2020, the Colorado Court of Appeals affirmed the judgment of the trial court in favor of the Company. In February 2021, the Company and its royalty owners received a gross payment of approximately $107 million from WGL, which was in full satisfaction and discharge of the June 2019 judgment entered in favor of the Company.

Other

The Company is party to various other legal proceedings and claims in the ordinary course of its business. The Company believes that certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

In addition, pending litigation against the Company and other similarly situated peer operators could have an impact on the methods for determining the amount of permitted post-production costs and types of costs that have been, and may be, deducted from royalty payments, among other things. While the amounts claimed could be material, we are unable to predict with certainty the ultimate outcome of such claims and proceedings. Rulings were recently received in two cases to which the Company is a party, and where the plaintiffs alleged, and the court found, that certain post-production costs may not be deducted: a non-class action lawsuit in West Virginia and a class action lawsuit in Ohio. In each case, the alleged damages were not material. The Company will continue to challenge the legal conclusions reached in each of these cases with respect to deductibility of post-production costs, and continues to analyze how these decisions may impact other cases to which the Company is a party. At this time, the Company cannot predict how these issues may ultimately be resolved, and therefore is also unable to estimate any potential damages, if any, that may result. The Company accrues for litigation, claims and proceedings when liability is both probable and the amount can be reasonably estimated, and does not currently have any material amounts accrued with respect to its pending litigation matters.

(16) Related Parties

Substantially all of Antero Midstream's revenues were and are derived from transactions with Antero Resources. See Note 17—Reportable Segments to the consolidated financial statements for the operating results of the Company's reportable segments.

(17) Reportable Segments

(a) Summary of Reportable Segments

The Company's operations, which are located in the United States, are organized into three reportable segments: (i) the exploration, development and production of natural gas, NGLs and oil; (ii) marketing and utilization of excess firm transportation capacity and (iii) midstream services through the Company's equity method investment in Antero Midstream. Substantially all of the Company's production revenues are attributable to customers located in the United States; however, some of the Company's production revenues are attributable to customers who then transport the Company's production to foreign countries for resale or consumption. These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Management evaluates the performance of the Company's business segments based on operating income (loss). General and administrative expenses were allocated to the midstream segment based on the nature of the expenses and on a combination of the segments' proportionate share of the Company's consolidated property and equipment, capital expenditures and labor costs, as applicable. General and administrative expenses related to the marketing segment are not allocated because they are immaterial. Other income, income taxes and interest expense are primarily managed and evaluated on a consolidated basis. Intersegment sales were transacted at prices which approximate market. Accounting policies for each segment are the same as the Company's accounting policies described in Note 2—Summary of Significant Accounting Policies to the consolidated financial statements.

Exploration and Production

The exploration and production segment is engaged in the development, production, exploration and acquisition of natural gas, NGLs and oil properties located in the Appalachian Basin. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs and oil from unconventional formations.

Marketing

Where feasible, the Company purchases and sells third-party natural gas and NGLs and markets its excess firm transportation capacity, or engages third parties to conduct these activities on the Company's behalf, in order to optimize the revenues from these transportation agreements. The Company has entered into long-term firm transportation agreements for a significant portion of its current and expected future production in order to secure guaranteed capacity to favorable markets.

Equity Method Investment in Antero Midstream

The Company receives midstream services through its equity method investment in Antero Midstream. Antero Midstream owns, operates and develops midstream energy infrastructure primarily to service the Company's production and completion activity in the Appalachian Basin. Antero Midstream's assets consist of gathering pipelines, compressor stations, interests in processing and fractionation plants and water handling assets. Antero Midstream provides midstream services to Antero Resources under long-term contracts.

(b) Reportable Segments Financial Information

The operating results and assets of the Company's reportable segments were as follows (in thousands):

	Year Ended December 31, 2021				
	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream	Elimination of Unconsolidated Affiliate	Consolidated Total
Sales and revenues:					
Third-party	$ 3,899,486	718,921	516	(516)	4,618,407
Intersegment	1,025	—	897,686	(897,686)	1,025
Total revenue	3,900,511	718,921	898,202	(898,202)	4,619,432
Operating expenses:					
Lease operating	96,793	—	—	—	96,793
Gathering, compression, processing, transportation and water handling	2,499,174	—	157,120	(157,120)	2,499,174
General and administrative	145,006	—	63,838	(63,838)	145,006
Depletion, depreciation and amortization	742,009	—	108,790	(108,790)	742,009
Impairment of property and equipment	90,523	—	5,042	(5,042)	90,523
Other	210,369	811,698	8,085	(8,085)	1,022,067
Total operating expenses	3,783,874	811,698	342,875	(342,875)	4,595,572
Operating income (loss)	$ 116,637	(92,777)	555,327	(555,327)	23,860
Equity in earnings of unconsolidated affiliates	$ 77,085	—	90,451	(90,451)	77,085
Capital expenditures for segment assets	$ 715,936	—	232,825	(232,825)	715,936

	Year Ended December 31, 2022				
	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream	Elimination of Unconsolidated Affiliate	Consolidated Total
Sales and revenues:					
Third-party	$ 6,720,212	416,758	2,622	(2,622)	7,136,970
Intersegment	1,466	—	917,363	(917,363)	1,466
Total revenue	6,721,678	416,758	919,985	(919,985)	7,138,436
Operating expenses:					
Lease operating	99,595	—	—	—	99,595
Gathering, compression, processing, transportation and water handling	2,605,380	—	180,254	(180,254)	2,605,380
General and administrative	172,909	—	62,125	(62,125)	172,909
Depletion, depreciation and amortization	680,600	—	131,762	(131,762)	680,600
Impairment of property and equipment	149,731	—	3,702	(3,702)	149,731
Other	325,012	531,304	2,676	(2,676)	856,316
Total operating expenses	4,033,227	531,304	380,519	(380,519)	4,564,531
Operating income (loss)	$ 2,688,451	(114,546)	539,466	(539,466)	2,573,905
Equity in earnings of unconsolidated affiliates	$ 72,327	—	94,218	(94,218)	72,327
Capital expenditures for segment assets	$ 943,971	—	298,924	(298,924)	943,971

	Year Ended December 31, 2023					
	Exploration and Production		Marketing	Equity Method Investment in Antero Midstream	Elimination of Unconsolidated Affiliate	Consolidated Total
Sales and revenues:						
Third-party	$	4,473,969	206,122	1,414	(1,414)	4,680,091
Intersegment		1,881	—	1,040,357	(1,040,357)	1,881
Total revenue		4,475,850	206,122	1,041,771	(1,041,771)	4,681,972
Operating expenses:						
Lease operating		118,441	—	—	—	118,441
Gathering, compression, processing, transportation and water handling		2,642,358	—	213,165	(213,165)	2,642,358
General and administrative		224,516	—	71,068	(71,068)	224,516
Depletion, depreciation and amortization		689,966	—	136,059	(136,059)	689,966
Impairment of property and equipment		51,302	—	146	(146)	51,302
Other		193,531	308,728	9,471	(9,471)	502,259
Total operating expenses		3,920,114	308,728	429,909	(429,909)	4,228,842
Operating income (loss)	$	555,736	(102,606)	611,862	(611,862)	453,130
Equity in earnings of unconsolidated affiliates	$	82,952	—	105,456	(105,456)	82,952
Capital expenditures for segment assets	$	1,131,863	—	183,733	(183,733)	1,131,863

	As of December 31, 2022					
	Exploration and Production		Marketing	Equity Method Investment in Antero Midstream	Elimination of Unconsolidated Affiliate	Consolidated Total
Investments in unconsolidated affiliates	$	220,429	—	652,767	(652,767)	220,429
Total assets		14,081,077	36,962	5,791,320	(5,791,320)	14,118,039

	As of December 31, 2023					
	Exploration and Production		Marketing	Equity Method Investment in Antero Midstream	Elimination of Unconsolidated Affiliate	Consolidated Total
Investments in unconsolidated affiliates	$	222,255	—	626,650	(626,650)	222,255
Total assets		13,602,297	17,117	5,737,618	(5,737,618)	13,619,414

(18) Subsidiary Guarantors

Antero Resources’ Senior Notes are fully and unconditionally guaranteed by Antero Resources’ existing subsidiaries that guarantee the Credit Facility. In the event a subsidiary guarantor is sold or disposed of (whether by merger, consolidation, the sale of a sufficient amount of its capital stock so that it no longer qualifies as a “Subsidiary” of Antero (as defined in the indentures governing the notes) or the sale of all or substantially all of its assets (other than by lease)) and whether or not the subsidiary guarantor is the surviving entity in such transaction to a person that is not Antero or a restricted subsidiary of Antero, such subsidiary guarantor will be released from its obligations under its subsidiary guarantee if the sale or other disposition does not violate the covenants set forth in the indentures governing the notes.

In addition, a subsidiary guarantor will be released from its obligations under the indentures and its guarantee, upon the release or discharge of the guarantee of other Indebtedness (as defined in the indentures governing the notes) that resulted in the creation of such guarantee, except a release or discharge by or as a result of payment under such guarantee; if Antero designates such subsidiary as an unrestricted subsidiary and such designation complies with the other applicable provisions of the indentures governing the notes or in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the notes.

The tables set forth below present summarized financial information of Antero, as parent, and its guarantor subsidiaries (in thousands). The Company's wholly owned subsidiaries are not restricted from making distributions to the Company.

Balance Sheets

	December 31,	
	2022	2023
Current assets	$ 739,104	453,581
Noncurrent assets	12,663,911	12,562,439
Total assets	$ 13,403,015	13,016,020
Accounts payable, related parties	$ 80,708	86,284
Other current liabilities	1,668,426	1,360,102
Total current liabilities	1,749,134	1,446,386
Noncurrent liabilities	5,306,539	4,951,464
Total liabilities	$ 7,055,673	6,397,850

Statement of Operations

	Year Ended December 31, 2023
Revenues	$ 4,539,184
Operating expenses	4,184,979
Income from operations	354,205
Net income and comprehensive income including noncontrolling interests	242,919
Net income and comprehensive income attributable to Antero Resources Corporation	$ 242,919

(19) Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The tables below set forth supplemental information regarding the Company's consolidated oil and gas producing activities (in thousands). The amounts shown include the Company's net working interests in all of its oil and gas properties.

(a) Capitalized Costs Relating to Oil and Gas Producing Activities

	Year Ended December 31,	
	2022	2023
Proved properties	$ 13,234,777	13,908,804
Unproved properties	997,715	974,642
Total oil and gas properties	14,232,492	14,883,446
Accumulated depletion	(4,624,674)	(4,996,691)
Net capitalized costs	$ 9,607,818	9,886,755

(b) Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2021	2022	2023
Acquisition costs:			
Unproved property	$ 79,138	149,009	151,135
Development costs	581,352	775,106	956,267
Exploration costs	19,822	5,543	8,079
Total costs incurred	$ 680,312	929,658	1,115,481

(c) Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2021	2022	2023
Revenues	$ 5,790,759	8,294,749	4,276,445
Operating expenses:			
Production expenses	2,793,877	2,992,381	2,919,654
Exploration expenses	1,164	3,651	2,691
Depletion	735,687	737,504	682,109
Impairment of unproved properties	90,523	98,324	51,302
Results of operations before income tax expense	2,169,508	4,462,889	620,689
Income tax expense	(520,168)	(959,477)	(135,063)
Results of operations	$ 1,649,340	3,503,412	485,626

(d) Oil and Gas Reserves

Net proved oil and gas reserves for the years ended December 31, 2021, 2022 and 2023 were prepared by the Company's reserve engineers and audited by DeGolyer and MacNaughton ("D&M") utilizing data compiled by the Company. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and timing of future development costs. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. All reserves are located in the United States.

Proved reserves are the estimated quantities of oil, condensate, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The Company estimates proved reserves using average prices received for the previous 12 months.

Proved undeveloped reserves include drilling locations that are more than one offset location away from productive wells and are reasonably certain of containing proved reserves and which are scheduled to be drilled within five years under the Company's development plans. The Company's development plans for drilling scheduled over the next five years are subject to many uncertainties and variables, including availability of capital, future commodity prices, net cash provided by operating activities, future drilling and completion costs, and other economic factors.

The tables below set forth the changes in quantities of proved reserves and net quantities of proved developed and proved undeveloped reserves for the periods indicated. This information includes the Company's royalty and net working interest share of the reserves in oil and gas properties.

	Natural Gas (Bcf)	NGLs (MMBbl)	Oil and Condensate (MMBbl)	Equivalents (Bcfe)
Proved reserves:				
December 31, 2020 (1)	10,025	1,236	33	17,635
Revisions	993	77	6	1,486
Extensions, discoveries and other additions	349	18	2	472
Production	(826)	(58)	(4)	(1,194)
Sales	(337)	(54)	(1)	(670)
December 31, 2021 (1)	10,204	1,219	36	17,729
Revisions	427	32	(4)	596
Extensions, discoveries and other additions	437	25	2	604
Production	(798)	(59)	(3)	(1,170)
December 31, 2022 (1)	10,270	1,217	31	17,759
Revisions	863	54	—	1,187
Extensions, discoveries and other additions	296	18	2	413
Production	(815)	(67)	(4)	(1,238)
December 31, 2023 (1)	10,614	1,222	29	18,121

(1) Proved reserves for the noncontrolling interests in Martica as of December 31, 2021 were 167 Bcfe, which consisted of 101 Bcf of natural gas, 11 MMBbl of NGLs and 0.4 MMBbl of oil and condensate. Proved reserves for the noncontrolling interests in Martica as of December 31, 2022 were 92 Bcfe, which consisted of 71 Bcf of natural gas, 3 MMBbl of NGLs and 0.2 MMBbl of oil and condensate. Proved reserves for the noncontrolling interests in Martica as of December 31, 2023 were 75 Bcfe, which consisted of 58 Bcf of natural gas, 3 MMBbl of NGLs and 0.1 MMBbl of oil and condensate.

	Natural Gas (Bcf)	NGLs (MMBbl)	Oil and Condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2021 (1)	7,395	876	17	12,753
December 31, 2022 (1)	7,699	930	16	13,373
December 31, 2023 (1)	7,912	963	15	13,783
Proved undeveloped reserves:				
December 31, 2021 (2)	2,809	343	19	4,976
December 31, 2022 (2)	2,571	287	15	4,386
December 31, 2023 (2)	2,702	259	14	4,338

(1) Proved developed reserves for the noncontrolling interests in Martica as of December 31, 2021 were 133 Bcfe, which consisted of 78 Bcf of natural gas, 9 MMBbl of NGLs and 0.2 MMBbl of oil and condensate. Proved developed reserves for the noncontrolling interests in Martica as of December 31, 2022 were 91 Bcfe, which consisted of 70 Bcf of natural gas, 3 MMBbl of NGLs and 0.2 MMBbl of oil and condensate. Proved developed reserves for the noncontrolling interests in Martica as of December 31, 2023 were 75 Bcfe, which consisted of 58 Bcf of natural gas, 3 MMBbl of NGLs and 0.1 MMBbl of oil and condensate.

(2) Proved undeveloped reserves for the noncontrolling interests in Martica as of December 31, 2021 were 34 Bcfe, which consisted of 23 Bcf of natural gas, 2 MMBbl of NGLs and 0.2 MMBbl of oil and condensate. Proved undeveloped reserves for the noncontrolling interests in Martica as of December 31, 2022 were 1 Bcfe, which consisted entirely of natural gas. There were no proved undeveloped reserves for the noncontrolling interests in Martica as of December 31, 2023.

Significant changes in proved reserves for the years ended December 31, 2021, 2022 and 2023 include the following:

2021 Proved Reserve Changes

- Extensions, discoveries, and other additions of 472 Bcfe resulted from delineation and development drilling in the Appalachian Basin.
- Net upward revisions of 1,486 Bcfe include:

- o Net upward revision of 651 Bcfe related to optimization to the Company's five-year development plan. This figure includes upward revisions of 1,475 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to the Company's five-year development plan, and downward revisions of 824 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
- o Net upward performance revisions of 565 Bcfe.
- o Upward revisions of 149 Bcfe due to increases in prices for natural gas, NGLs and oil.
- o Upward revisions of 121 Bcfe are due to an increase in the Company's assumed future ethane recovery.

- Sales of reserves of 670 Bcfe related to the drilling partnership.

2022 Proved Reserve Changes

- Extensions, discoveries, and other additions of 604 Bcfe resulted from delineation and development drilling in the Appalachian Basin.
- Net upward revisions of 596 Bcfe include:
  - o Net upward revisions of previous estimates of 414 Bcfe primarily due to changes in ownership interests.
  - o Net upward revision of 92 Bcfe related to optimization to the Company's five-year development plan. This figure includes upward revisions of 692 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to the Company's five-year development plan, and downward revisions of 600 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
  - o Upward revisions of 88 Bcfe are due to an increase in the Company's assumed future ethane recovery.
  - o Upward revisions of 2 Bcfe due to increases in prices for natural gas, NGLs and oil.

2023 Proved Reserve Changes

- Extensions, discoveries, and other additions of 413 Bcfe resulted from delineation and development drilling in the Appalachian Basin.
- Net upward revisions of 1,187 Bcfe include:
  - o Net upward revisions of previous estimates of 814 Bcfe includes 846 Bcfe for increases in the Company's ownership interests, partially offset by downward revisions of 32 Bcfe related to changes in the Company's reserve forecast and operation cost estimates.
  - o Net upward revision of 454 Bcfe related to optimization to the Company's five-year development plan. This figure includes upward revisions of 698 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to the Company's five-year development plan, and downward revisions of 244 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
  - o Downward revisions of 81 Bcfe due to decreases in prices for natural gas, NGLs and oil.

(e) Standardized Measure of Discounted Future Net Cash Flow

The standardized measure relating to proved oil and reserves was prepared in accordance with the provisions of ASC 932. Future cash inflows were computed by applying historical 12 month unweighted first day of the month average prices. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of available NOL carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

The following table sets forth the Standardized Measure of the discounted future net cash flows attributable to the Company's proved reserves (in millions):

	Year Ended December 31,		
	2021	2022	2023
Future cash inflows	$ 74,622	109,052	58,061
Future production costs	(34,665)	(39,378)	(41,887)
Future development costs	(1,704)	(2,073)	(2,027)
Future net cash flows before income tax	38,253	67,601	14,147
Future income tax expense	(7,813)	(13,692)	(2,178)
Future net cash flows	30,440	53,909	11,969
10% annual discount for estimated timing of cash flows	(17,007)	(30,345)	(6,874)
Standardized measure of discounted future net cash flows (1)	$ 13,433	23,564	5,095

(1) The standardized measure of discounted future net cash flows for the noncontrolling interests in Martica were $501 million, $458 million and $170 million for the years ended December 31, 2021, 2022 and 2023, respectively.

The Company used the following 12-month weighted average prices to estimate its total equivalent reserves (per Mcfe):

	Year Ended December 31,		
	2021	2022	2023
12-month weighted average price	$ 4.21	6.14	3.20

(f) Changes in Standardized Measure of Discounted Future Net Cash Flow

The changes in the Standardized Measure relating to proved oil and natural gas reserves, which were prepared in accordance with the provisions of ASC 932, are as follows (in millions):

	Year Ended December 31,		
	2021	2022	2023
Sales of oil and gas, net of productions costs	$ (2,917)	(5,302)	(1,357)
Net changes in prices and production costs (1)	14,099	13,793	(25,672)
Development costs incurred during the period	454	448	637
Net changes in future development costs	(117)	(289)	(96)
Extensions, discoveries and other additions	504	1,068	69
Divestitures	(125)	—	—
Revisions of previous quantity estimates	2,543	1,475	190
Accretion of discount	121	1,655	2,947
Net change in income taxes	(3,115)	(2,787)	5,069
Changes in timing and other	776	70	(256)
Net increase (decrease)	12,223	10,131	(18,469)
Beginning of year	1,210	13,433	23,564
End of year (2)	$ 13,433	23,564	5,095

(1) The net changes in prices and production costs are calculated prior to the consideration of future income tax expense. The Standardized Measure included future income tax expense of $7.8 billion, $13.7 billion and $2.2 billion for the years ended December 31, 2021, 2022 and 2023, respectively.

(2) The standardized measure for the noncontrolling interests in Martica were $501 million, $458 million and $170 million for the years ended December 31, 2021, 2022 and 2023, respectively.