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, 2025

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 (State or other jurisdiction of incorporation or organization)	**80-0162034** (IRS Employer Identification No.)
1615 Wynkoop Street, Denver, Colorado (Address of principal executive offices)	**80202** (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, 2025, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $11.7 billion based on the $40.28 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 6, 2026 (in thousands): 308,525

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.

Antero Midstream Partners. Antero Midstream Partners LP, a wholly owned subsidiary of Antero Midstream.

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 Mcf 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. As the context requires, (i) for any date prior to July 30, 2024, the senior secured revolving credit facility pursuant to the Sixth Amended and Restated Credit Agreement, dated as of October 26, 2021, and (ii) for July 30, 2024 and thereafter, the senior unsecured revolving credit facility pursuant to the Amended and Restated Credit Agreement, dated as of July 30, 2024.

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.

HG Acquisition. Our acquisition of 100% of the issued and outstanding equity interests of HG Energy II Production Holdings, LLC, a Delaware limited liability company, from HG Energy II LLC, a Delaware limited liability company.

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.

ICE. Intercontinental Exchange, Inc.

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, 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 one barrel of oil, condensate or NGLs converted 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 Mcf 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.

OPIS. Oil Price Information Service.

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 8.375% senior notes due July 15, 2026, 7.625% senior notes due February 1, 2029, 5.375% senior notes due March 1, 2030 and 5.400% senior notes due February 1, 2036, 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.

Term Loan A Facility. The unsecured three-year term loan facility with the Royal Bank of Canada, RBC Capital Markets and JPMorgan Chase Bank, N.A. dated February 3, 2026.

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.

Utica Shale Divestiture. Our divestiture of substantially all of our Utica Shale oil and gas assets located in Ohio.

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:

- natural gas, NGLs and oil prices;
- our ability to execute our business strategy;
- our production and natural gas, NGLs and oil 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, capital expenditures, working capital requirements and the repayment or refinancing of indebtedness;
- risks associated with the successful integration and future performance of the HG Acquisition;
- risks associated with the Utica Shale Divestiture, including the risk that it is not consummated on the terms expected or on the anticipated schedule, or at all;
- our ability to execute our return of capital program;
- timing and amount of future production of natural gas, NGLs and oil;
- impacts of geopolitical events, including the conflicts in Ukraine, Venezuela and in the Middle East, and world health events;
- our ability to meet minimum volume commitments and to utilize or monetize our firm transportation commitments;
- marketing of natural gas, NGLs and oil;
- our future drilling plans;
- our projected well costs;
- our hedging strategy and results;
- costs of developing our properties;
- uncertainty regarding our future operating results;
- operations of Antero Midstream;
- competition;
- government regulations and changes in laws;
- pending legal or environmental matters;
- leasehold or business acquisitions;

- our ability to achieve our GHG reduction targets and the costs associated therewith;
- general economic conditions;
- credit markets; 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 45% 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.
- Legal proceedings brought against us could result in substantial liabilities and materially and adversely impact our financial condition.
- 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.
- Sustainability 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

- We may not achieve the intended benefits of the HG Acquisition, and the HG Acquisition may disrupt our existing plans or operations.
- We may not complete the Utica Shale Divestiture within the anticipated timeframe or at all.
- 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.
- 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 risks 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, 2025, we held approximately 537,000 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. Unless expressly stated otherwise, the operating and financial information presented in this Annual Report on Form 10-K does not give effect to the completion of the HG Acquisition or the Utica Shale Divestiture.

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, 2025, we owned 29% 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, 2025					Three Months Ended December 31, 2025
	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	19,149	$ 9,679	1,551	536,526	1,279	3,511
Discounted future income taxes		(1,569)				
Standardized Measure [6]		$ 8,110				

(1) Estimated proved reserve volumes and values were calculated assuming partial ethane recovery, with rejection of the remaining ethane and using the unweighted 12 month average of the first-day-of-the-month prices ("SEC reserves prices") for the year ended December 31, 2025, which were $3.42 per Mcf for natural gas, $14.09 per Bbl for ethane, $39.43 per Bbl for C3+ NGLs and $52.34 per Bbl for oil for the Appalachian Basin based on Henry Hub and WTI reference prices of $3.39 per MMBtu and $65.34 per Bbl, respectively.
(2) Proved reserves for the noncontrolling interests in Martica as of December 31, 2025 were 38 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 18—Supplemental Information on Oil and Gas Producing Activities to our consolidated financial statements for additional 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 296 locations classified as proved undeveloped and 983 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, 2025 was $72 million.

For the year ended December 31, 2025, our total consolidated capital expenditures were $797 million, including drilling and completion expenditures of $658 million, leasehold additions of $131 million and other capital expenditures of $8 million. We completed 61 net horizontal wells during the year ended December 31, 2025. Our capital budget for 2026 is $1.1 billion to $1.3 billion and includes: $1.0 billion for drilling and completions, $100 million for leasehold expenditures and up to $200 million for discretionary growth capital that is dependent on commodity prices. Our capital budget reflects the closing of the HG Acquisition on February 3, 2026 and assumes the closing of the Utica Shale Divestiture during February 2026. We do not budget for acquisitions. During 2026, we plan to complete 70 to 80 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. In recent years, we have significantly reduced our leverage profile and will prioritize it on an ongoing basis.

Expanding Our Long-Lived Asset Base in the Core Marcellus in West Virginia which has Product Diversity and Access to Multiple End Markets

We have assembled a portfolio of long lived properties primarily in the core of the Marcellus Shale in West Virginia that are characterized by what we believe to be high repeatability and low geologic risk. The HG Acquisition expands our core position in West Virginia, where we have a substantial inventory of liquids-rich and dry gas locations. Additionally, we have access to move our production to multiple end markets, both domestically and internationally, through long-term firm takeaway capacity on major pipelines.

Focus on Reducing Cash Costs and Expanding Margins

We are focused on reducing cash costs and expanding margins through incremental dry gas development and lowering commitments on firm transportation over time. The HG Acquisition contributes to this initiative through its increase to our scale and its dry gas production sold locally in the Appalachian Basin.

Integrated Business Platform

We believe it is critical in Appalachia to have integrated development of the resources in order to have the most capital efficient development and maximize price realizations. Therefore, we operate in the following reportable segments: (i) the exploration, development and production of natural gas, NGLs and oil ("exploration and production"); (ii) midstream services through our equity method investment in Antero Midstream ("equity method investment in Antero Midstream") and (iii) marketing of excess firm transportation capacity ("marketing").

Hedge Program

We utilize a hedging program to mitigate volatility in commodity prices and to protect certain of our expected future cash flows when circumstances warrant. We also use hedges as a tool to protect underlying valuations of our acquisition program.

Acquisitions

HG Acquisition

On December 5, 2025, we entered into a definitive agreement to acquire 100% of the issued and outstanding equity interests of HG Energy II Production Holdings, LLC ("HG Production") from HG Energy II LLC ("HG Energy") for total cash consideration of $2.8 billion, subject to the terms and conditions thereof. The HG Acquisition includes approximately 385,000 net acres in the core of the Marcellus Shale in West Virginia. Pursuant to the same agreement, Antero Midstream Partners agreed to acquire 100% of the issued and outstanding equity interests of HG Energy II Midstream Holdings, LLC ("HG Midstream") from HG Energy for cash consideration of $1.1 billion, subject to the terms and conditions thereof ("HG Midstream Acquisition"). The HG Midstream Acquisition includes gathering pipelines and integrated water handling assets in the core of the Marcellus Shale in West Virginia. These acquisitions closed on February 3, 2026. See Note 3—Transactions to our consolidated financial statements for additional information.

Asset Acquisitions

During the year ended December 31, 2025, the Company acquired additional working and royalty interests in certain Antero-operated producing wells for a total of approximately $260 million, before closing adjustments. See Note 3—Transactions to our consolidated financial statements for additional information.

Utica Shale Divestiture

On December 5, 2025, we entered into a definitive agreement with two third-party buyers (collectively, the "Buyer Parties") to sell substantially all of our Utica Shale oil and gas assets (the "Utica Shale Properties") for aggregate cash consideration of $800 million, subject to the terms and conditions thereof. The Utica Shale Properties include approximately 80,000 gross (70,000 net) acres located in Ohio and proved reserves of approximately 600 Bcfe as of December 31, 2025. The Utica Shale Divestiture is expected to close in February 2026, subject to the satisfaction of certain customary closing conditions. See Note 3—Transactions to our consolidated financial statements for additional information.

Drilling Partnerships

2021-2024 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 ("2021-2024 Drilling Partnership"). Under the terms of the arrangement, each year in which QL participated represented an annual tranche, and QL was 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 developed and managed the drilling program associated with each tranche, including the selection of wells. Additionally, for each annual tranche, we entered into assignments, bills of sale and conveyances pursuant to which QL was conveyed a proportionate working interest percentage in each well spud in that year, which conveyances are not subject to any reversion. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche were 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.

Under the terms of the arrangement, QL funded development capital of 20% for wells spud in 2021 and 2024, 15% for wells spud in 2022 and 2023, which funding amounts represented QL's proportionate working interest in such wells. Additionally, we were entitled to receive a carry in the form of a one-time payment from QL for each annual tranche if the IRR for such tranche exceeded certain specified returns, which was determined no earlier than October 31 and no later than December 1 following the end of each tranche year. We received a total carry of $117 million for the 2021-2024 Drilling Partnership. See Note 3—Transactions to our consolidated financial statements for additional information.

2025 Drilling Partnership

On December 11, 2024, we entered into a drilling partnership with an unaffiliated third-party (the "2025 Drilling Partnership"). Under the terms of the arrangement, the third-party participated in and funded a share of total development capital expenses for wells spud by Antero during the 2025 calendar year. For each well spud during the 2025 calendar year, the third-party received a 15% working interest in such wells and funded greater than 15% of total development capital expenses for such wells. Subject to the preceding sentence, for any wells spud in the calendar year 2025, the third-party 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. Additionally, for each well in the partnership, we entered into an assignment, bill of sale and conveyance pursuant to which the third-party was conveyed a proportionate working interest percentage in such well, which conveyances are not subject to any reversion. See Note 3—Transactions to our consolidated financial statements for additional information.

Our Properties and Operations

Reserves

The table below summarizes our estimated proved reserves as of December 31, 2024 and 2025, 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, 2024 (1)					
Proved developed reserves	7,876	966	13	13,747	77 %
Proved undeveloped reserves	2,727	227	10	4,156	23 %
Total (2)	10,603	1,193	23	17,903	100 %
As of December 31, 2025 (1)					
Proved developed reserves	8,388	1,003	12	14,478	76 %
Proved undeveloped reserves	3,382	205	10	4,671	24 %
Total (2)	11,770	1,208	22	19,149	100 %

(1) The SEC reserves prices for the year ended December 31, 2024 were $2.12 per Mcf for natural gas, $10.51 per Bbl for ethane, $42.34 per Bbl for C3+ NGLs and $61.60 per Bbl for oil for the Appalachian Basin based on Henry Hub and WTI reference prices of $2.13 per MMBtu and $75.54 per Bbl, respectively. The SEC reserves prices for the year ended December 31, 2025 were $3.42 per Mcf for natural gas, $14.09 per Bbl for ethane, $39.43 per Bbl for C3+ NGLs and $52.34 per Bbl for oil for the Appalachian Basin based on Henry Hub and WTI reference prices of $3.39 per MMBtu and $65.34 per Bbl, respectively.

(2) Proved developed reserves attributable to the noncontrolling interests in Martica were 57 Bcfe and 38 Bcfe as of December 31, 2024 and 2025, respectively. There were no proved undeveloped reserves attributable to the noncontrolling interests in Martica as of December 31, 2024 and 2025.

Proved Reserves

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

Proved reserves, December 31, 2024	**17,903**
Extensions, discoveries and other additions	665
Revisions of previous estimates	451
Revisions to five-year development plan	743
Price revisions	137
Acquisition of reserves	506
Production	(1,256)
Proved reserves, December 31, 2025	**19,149**

Extensions and discoveries of 665 Bcfe of proved reserves resulted from delineation and developmental drilling in the Appalachian Basin. Revisions of previous estimates of 451 Bcfe primarily relates to increases in our ownership interests. Revisions to the five-year development plan of 743 Bcfe includes an upward revision of 1,045 Bcfe primarily 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 302 Bcfe for locations that were not developed within five years of initial booking as proved reserves. Price revisions of 137 Bcfe are due to an increase in price for natural gas between periods, partially offset by decreases in prices for oil and NGLs for the year ended December 31, 2025. Acquisition of reserves related to the Company's acquisitions of additional working and royalty interests in certain Antero-operated producing wells for the year ended December 31, 2025. Estimated proved reserves as of December 31, 2025 totaled 19,149 Bcfe, an increase of 7% from December 31, 2024.

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, 2024	**4,156**
Extensions, discoveries and other additions	665
Revisions of previous estimates	382
Revisions to five-year development plan	730
Reclassifications to proved developed reserves	(1,262)
Proved undeveloped reserves, December 31, 2025	**4,671**

Extensions and discoveries of 665 Bcfe of proved undeveloped reserves resulted from delineation and developmental drilling in the Appalachian Basin. Revisions of previous estimates of 382 Bcfe primarily relates to increases in our ownership interests. Revisions to the five-year development plan of 730 Bcfe includes an upward revision of 1,030 Bcfe primarily 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 300 Bcfe for locations that were not developed within five years of initial booking as proved reserves. Estimated proved undeveloped reserves as of December 31, 2025 totaled 4,671 Bcfe, an increase of 12% from December 31, 2024.

During the year ended December 31, 2025, we converted 1,262 Bcfe, or 30% of our proved undeveloped reserves to proved developed reserves and incurred drilling and completion costs of $457 million. We spent an additional $221 million on development costs related primarily to drilled and uncompleted wells and properties in the proved undeveloped classification as of December 31, 2025, resulting in total development costs incurred of $678 million, as disclosed in Note 18—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, 2025 are $2.3 billion, or $0.49 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, 2025, we believe that net cash provided by operating activities will be sufficient to finance such future development costs. While our development program is primarily focused on drilling our proved undeveloped reserves, we will also continue to drill leasehold delineation wells and build on our current leasehold position. 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, 2025, an estimated 3,428 of our net leasehold acres, containing 129 gross wells (11 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 $11 million to renew the 3,428 acres based upon current leasing authorizations and option to extend payments. Proved undeveloped reserves of 294 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 29 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, 2023, 2024 and 2025 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, 2025 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 15 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 reserves prices as of December 31, 2025.

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, 2023, 2024 and 2025. 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,		
	2023	**2024**	**2025**
Production data [1] [2]:			
Natural gas (Bcf)	815	793	808
C2 Ethane (MBbl)	24,657	30,391	29,842
C3+ NGLs (MBbl)	41,927	42,434	42,010
Oil (MBbl)	3,874	3,693	2,899
Combined (Bcfe)	1,238	1,252	1,256
Daily combined production (MMcfe/d)	3,392	3,421	3,442
Average prices before effects of derivative settlements [3]:			
Natural gas (per Mcf)	$ 2.69	2.29	3.56
C2 Ethane (per Bbl) [4]	$ 10.14	9.05	11.91
C3+ NGLs (per Bbl)	$ 37.85	42.23	38.83
Oil (per Bbl)	$ 63.80	62.29	51.80
Combined average sales prices before effects of derivative settlements (per Mcfe) [1]	$ 3.45	3.29	3.99
Combined average sales prices after effects of derivative settlements (per Mcfe) [1]	$ 3.43	3.30	3.97
Average Costs (per Mcfe):			
Lease operating	$ 0.10	0.09	0.11
Gathering, compression, processing and transportation	$ 2.13	2.16	2.27
Production and ad valorem taxes	$ 0.13	0.17	0.13
Marketing, net	$ 0.06	0.05	0.05
General and administrative (excluding equity-based compensation)	$ 0.13	0.13	0.14
Depletion, depreciation, amortization and accretion	$ 0.61	0.61	0.60

(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 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, 2023, 2024 and 2025 includes $15 million, $2 million and $1 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, 2023, 2024 and 2025 would have been $9.55 per Bbl, $8.99 per Bbl and $11.88 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, 2025. All of our acreage is located in the Appalachian Basin primarily in West Virginia and Ohio. Our Ohio acreage is included in the Utica Shale Divestiture. Approximately 86% 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.

	Gross	**Net**
Developed acres	315,606	293,451
Undeveloped acres [1]	249,982	243,075
Total acres [1]	565,588	536,526

(1) There are 7,985 gross (7,847 net), 23,258 gross (21,610 net) and 13,418 gross (12,872 net) acres subject to expiration during the years ending December 31, 2026, 2027 and 2028, 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

All of our productive wells are natural gas wells located in the Appalachian Basin. As of December 31, 2025, we had 1,933 gross and 1,775 net productive wells, including 260 gross and 236 net vertical 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, 2023, 2024 and 2025. 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,					
	2023		2024		2025 (1)	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	87	70	51	41	78	61
Dry	—	—	—	—	—	—
Total development wells	87	70	51	41	78	61

(1) Well counts exclude 18 gross wells (14 net wells) that were in the process of being completed as of December 31, 2025.

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 gas gathering and compression infrastructure that services our production were $132 million and $91 million for the years ended December 31, 2024 and 2025, 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, 2025, Antero Midstream's gathering and compression systems included 731 miles of gas gathering pipelines and 4.8 Bcf/d of compression capacity in the Appalachian Basin. We also have access to additional third-party gas gathering pipelines. 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)(2)	800	300	In service
Total	3,600	3,100	

(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.
(2) Our contracted capacity for these Seneca gas processing plants is included in the Utica Shale Divestiture.

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 that decreases to 200,000 MMBtu/d in 2030, and delivers gas to downstream contracts on MGT, NGPL and ANR Chicago. These REX contracts expire in 2030 and 2035. However, 300,000 MMBtu/d of our REX firm capacity is included in the Utica Shale Divestiture, and upon transaction closing and FERC approval, we will have 100,000 MMBtu/d on REX that expires in 2035.

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) Mountaineer Xpress Pipeline ("MXP"), (viii) Columbia Gas Transmission IPP Pool ("TCO IPP"), (ix) Gulf Xpress Pipeline ("GXP"), (x) Enterprise Products Partners ATEX Pipeline ("ATEX") and (xi) 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 and TCO west bound ("TCO WB") firm capacity of approximately 433,000 MMBtu/d and 746,000 MMBtu/d respectively, and our TCO WB increases to approximately 800,000 MMBtu/d in 2027. This firm transportation provides us with access to the local Appalachia and the Gulf Coast markets via the Tennessee and Columbia Gulf pipelines. We have 430,000 MMBtu/d of firm transportation on Columbia Gulf. These contracts expire at various dates from 2027 through 2058.

- TCO east bound firm capacity of approximately 356,000 MMBtu/d that delivers (i) 330,000 MMBtu/d of natural gas to the Cove Point LNG facility and (ii) approximately 26,000 MMBtu/d to the Atlantic Seaboard. These contracts expire at various dates from 2029 to 2038.

- SGG firm capacity of 900,000 MMBtu/d that transports gas from various gathering system interconnection points and the MarkWest Sherwood plant complex to the TCO WB System through 2030. However, our SGG minimum volume commitment decreases to 600,000 MMBtu/d in 2027.

- MXP firm capacity of 700,000 MMBtu/d that transports gas from the MarkWest Sherwood plant complex to Tennessee or Leach, Kentucky. We have approximately 183,000 MMBtu/d on GXP, which continues from Leach, Kentucky to the Gulf Coast. These contracts expire in 2034.

- Rover Pipeline firm capacity of 840,000 MMBtu/d that connects the Appalachian Basin to Midwest and Gulf Coast markets via the ANR Chicago and ANR Gulf segments. These contracts expire at various dates from 2030 to 2033.

- 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. These contracts expire 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.

- 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 for 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 our consolidated financial statements for information on our minimum fees for such contracts. Based on current projected 2026 annual production guidance, we estimate that we could incur annual net marketing costs of $0.02 per Mcfe to $0.04 per Mcfe in 2026 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, 2025, our firm sales commitments through 2030 included:

Year Ending December 31,	Natural Gas (MMBtu/d)	Ethane (Bbl/d)	C3+ NGLs (Bbl/d)
2026	614,795	85,500	14,914
2027	600,000	86,500	—
2028	600,000	85,000	—
2029	530,000	75,000	—
2030	530,000	75,000	—

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 our 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, 2025, Antero Midstream owned and operated 236 miles of buried water pipelines and 187 miles of portable surface water pipelines in the Appalachian Basin. Additionally, as of December 31, 2025, Antero Midstream had the ability to store approximately 5 million barrels of fresh water in 33 impoundments equipped with transfer pumps located throughout our leasehold acreage.

Major Customers

See Note 2—Significant Accounting Policies to our consolidated financial statements for information on our major customers.

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 2025, FERC issued an order (Order No. 906) 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 $1,584,648 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 $1.5 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 waters of the United States ("WOTUS"). 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 and uncertainty, with the Corps and EPA pursuing several rulemakings since 2015 to attempt to define the scope of WOTUS. In September 2023, the EPA issued a WOTUS rule that is currently only implemented in 24 states due to ongoing litigation. However, in November 2025, the EPA and the Corps proposed a rule to further update and narrow this September 2023 definition of WOTUS, guided by the Sackett v. EPA decision. To the extent any judicial ruling, administrative rulemaking, or other action further changes 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.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as 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. In 2020, the Trump administration maintained the National Ambient Air Quality Standard ("NAAQS") for ozone at 70 parts per billion for both the 8-hour primary and secondary standards. We cannot predict what further actions, if any, and on what timeline, the Trump administration may take with respect to these regulations. 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. However, the EPA has recently announced plans to reconsider many of these rules under the Trump administration's deregulatory agenda and has, in the meantime, extended various compliance deadlines. 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

The EPA under previous presidential administrations 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. Such 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 also 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. Although the EPA has proposed to delay GHG reporting for the oil and gas sector until 2034, and to otherwise repeal GHG reporting requirements for other sectors, we cannot predict whether these efforts will ultimately be successful or that GHG reporting will not be required again in the future.

The federal regulation of methane from oil and gas facilities has been subject to substantial uncertainty in recent years. In December 2023, 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. However, in March 2025, the EPA announced plans to reconsider OOOOb and OOOOc, in line with the Trump administration's deregulatory agenda. Additionally, in November 2025, the EPA finalized an interim rule extending the compliance deadlines for certain provisions provided in OOOOb and OOOOc. Litigation challenging the EPA's final interim rule extending such compliance deadlines for new and existing oil and gas sources remains pending.

In August 2022, the Inflation Reduction Act ("IRA 2022") was signed into law, which appropriated significant federal funding for renewable energy initiatives and amended the Clean Air Act to require the EPA to impose and collect a first-time fee on the emission of excess methane above statutory methane emissions thresholds from sources required to report their GHG emissions to the EPA. In November 2024, the EPA issued a final rule implementing the methane emissions fee, although in February 2025, Congress repealed the rule under the Congressional Review Act. Additionally, under the One Big Beautiful Bill Act, Congress delayed the implementation of the methane emissions fee until 2034. Compliance with the methane emissions fee and other air pollution control and permitting requirements has 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 cannot predict what, when, or how the Trump administration may take further actions to rollback or otherwise revise existing methane-related regulations. Existing climate change-related regulation has already become a focus of the new Trump Administration. On his first day in office, President Trump signed several Executive Orders rescinding many of the previous administration's climate-related Executive Orders and associated initiatives. President Trump's directives included, amongst others, directing the EPA to reconsider its 2009 endangerment findings relating to GHGs, which provides regulatory justification for federal GHG permitting and methane emission control requirements, and directing the EPA to reconsider its use of Social Cost of GHG estimates in federal permitting decisions. To that end, in March 2025, the EPA announced formal reconsideration of both the Social Cost of GHG estimates and the 2009 endangerment finding and, in July 2025, released a proposal to rescind the latter. We cannot predict the ultimate impact of these actions on our business or results of operations.

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 risks and air quality, (ii) addressing stakeholder inquiries regarding our position on climate risks, 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.

We have taken several steps to manage methane and other emissions from our operations. 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 2025, we eliminated or replaced approximately 774 natural gas driven pneumatic devices, which brings the total number of pneumatic devices eliminated or replaced in our operations to approximately 7,779 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 this report, our methane leak loss rate in 2024 was 0.010%, calculated in accordance with ONE Future, well below the ONE Future voluntary industry target of 1%.

During 2025, our GHG/methane emission reduction efforts included the following activities:

- Continued our responsibly sourced gas certification effort that is Trustwell certified by Project Canary.
- Conducted four aerial flyovers of the majority of our well pad locations as part of our emissions monitoring initiatives.
- Eliminated or replaced approximately 774 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.
- Maintained a marginal abatement cost curve ("MACC") to effectively and systematically model emission reduction projects across our operations. Our MACC process is instrumental in evaluating the capital improvements required to achieve our emissions goals.
- Continued utilization of the following procedures or equipment in our operations:
    - Quarterly facility LDAR inspections, which in most cases 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.
    - Utilized our ESG Advisory Council together with our GHG/Methane Reduction Team to manage the identification, evaluation, monitoring, mitigation and adaptation, as applicable, of risks and opportunities related to the environment.

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 sustainability matters, see "Item 1A. Risk Factors—Business Operations—Sustainability matters and conservation measures may adversely impact our business."

Increasingly, oil and natural gas companies are exposed to litigation risks related to climate risks. We are not currently party to any such litigation, but could be named in future actions making similar claims of liability and, depending on the nature of the claims asserted and other factors, such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Our access to capital may be impacted by climate risk policies. Financial institutions may adopt policies that have the effect of reducing the funding provided to the oil and natural gas industry, although this trend has generally been decreasing. To the extent implemented or pursued, such policies and commitments 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. While we cannot predict how or to what extent sustainable lending and investment practices may impact our operations, 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, some states have adopted or are considering adopting laws requiring the disclosure of climate related risks. Lawsuits have been filed challenging the implementation of these laws, but we cannot predict the outcome of these suits at this time. Compliance with these laws, to the extent they are implemented and applicable to us, may result in additional costs related to 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 and could also increase our litigation risks relating to statements alleged to have been made by us or others in our industry regarding climate 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.

Moreover, climate risks 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.

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. 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.

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.

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 2025, nor do we anticipate that such expenditures will be material in 2026.

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, 2025, we had 632 full-time employees, including 47 in executive, finance, treasury, legal and administration, 37 in information technology, 19 in geology, 243 in production and operations, 184 in midstream and water, 53 in land and 49 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 17 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.

Equal Employment Opportunity and Workplace Culture

We are committed to building a culture where equal employment opportunity and a strong workplace culture are core philosophies across our operations. We prohibit all forms of unlawful discrimination and are 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 diverse backgrounds and perspectives as well as belonging. Finally, in line with these beliefs and our commitment to equal employment opportunity, 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 first of month prices for NYMEX Henry Hub natural gas ranged from a high of $4.42 per MMBtu to a low of $2.84 per MMBtu in 2025, and the calendar month average prices for NYMEX West Texas Intermediate crude oil ranged from a high of $75.10 per barrel to a low of $57.87 per barrel during the same period. Natural gas prices were substantially higher in 2025 than they were in 2024, while oil prices decreased substantially in 2025 as compared to 2024. 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 may enter into derivative contracts for a significant percentage of our expected production volumes. Assuming our 2026 production is the same as our production in 2025, approximately 42% of our total production is hedged through commodity derivatives. In addition, we have commodity derivative contracts in place for a portion of our 2027 production. Our current and potential future hedging activity may prevent us from realizing the near-term benefits of price increases above the levels of the hedges for the portion of our production that is hedged. 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, 2025, 24% of our total estimated proved reserves were classified as proved undeveloped. Our 4.7 Tcfe of estimated proved undeveloped reserves will require an estimated $2.3 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 12-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 45% 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 45% 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 294 Bcfe related to such acreage that is subject to renewal prior to drilling. In addition, 14% 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 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, 2025, we had 1,279 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 additional information on legal proceedings.

Sustainability matters and conservation measures may adversely impact our business.

Stakeholder attention to climate risks, societal expectations on companies related to climate risks, investor, regulatory and societal expectations regarding voluntary and mandatory sustainability 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. Any increased attention to climate risks 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 and, depending on the nature of the claims asserted and other factors, 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 sustainability matters from time to time, many of the statements in those voluntary disclosures are based on expectations and assumptions or hypothetical scenarios 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 sustainability-related disclosure is also evolving 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 or hypothetical scenarios are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established approach to identifying, measuring and reporting on many sustainability matters. In addition, we may announce various voluntary sustainability targets, including certain GHG emissions goals, and we could face unexpected material costs as a result of our efforts to maintain 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. A failure or a perception of failure (whether or not valid) to pursue, implement or adequately make progress against such sustainability strategies or achieve such sustainability goals or commitments could result in private litigation and damage to our reputation. In addition, while we may seek to 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 or heightened scrutiny of their methodologies. 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, have instituted 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 sustainability profile or transparency of our operations and products, we cannot guarantee that such participation or certification will have the intended results on our or our products' sustainability profile. Also, despite any aspirational goals, we may receive pressure from investors, lenders or other groups to adopt more aggressive climate or other sustainability-related goals, but we cannot guarantee that we will be able to implement such goals in whole or in part 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 sustainability plans or goals or stakeholder perceptions of certain statements made by us, others in our industry, 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 sustainability matters are becoming increasingly subject to heightened scrutiny from public and governmental authorities, as well as other parties, related to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential sustainability benefits. Additionally, certain employment practices and social initiatives are the subject of scrutiny by both those calling for the continued advancement of such policies, as well as those who believe they should be curbed, including government actors, and the complex regulatory and legal frameworks applicable to such initiatives continue to evolve. We cannot be certain of the impact of such regulatory, legal and other developments on our business. More recent political developments could mean that we face increasing criticism or litigation risks from certain "anti-ESG" parties, including various governmental agencies. Such sentiment may focus on our environmental commitments or our pursuit of certain employment practices or social initiatives that are alleged to be political or polarizing in nature or are alleged to violate laws based, in part, on changing priorities of, or interpretations by, federal agencies or state governments. Consideration of sustainability and social-related factors in our decision making could be subject to increasing scrutiny and objection from such anti-ESG parties. As a result, we may face increased litigation risks from private parties and governmental authorities related to our sustainability 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 and proxy voting recommendations processes for evaluating companies on their approach to sustainability matters. Such ratings, proxy advisory services, and reports may be used by some investors to inform their investment and voting decisions. While such ratings do not impact all investors' investments or voting decisions, unfavorable sustainability 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, certain institutional lenders may decide not to provide funding for oil and natural gas companies or the corresponding infrastructure projects based on climate related concerns, which could affect our access to capital for potential growth projects. Moreover, to the extent sustainability 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 sustainability 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 2025 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 2026 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 2026 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 growing regulatory landscape around data protection adds additional complexity to safeguarding this information. 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. The interconnected nature of our industry heightens the risk that a cybersecurity incident affecting one of our vendors, suppliers, customers or other business partners could propagate across the supply chain, potentially causing widespread operational or financial disruptions. 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. Some cyber incidents, such as surveillance, ransomware, or deepfake-based social engineering attacks, may remain undetected for some period of time. 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. While we maintain cyber insurance coverage to help mitigate financial risks associated with cyber incidents, such policies have limitations and do not cover all potential losses, such as reputational harm or regulatory fines. Accordingly, our cyber insurance may not provide coverage for all potential risks arising from cyber incidents. As cyberattacks increase globally in frequency and severity, coverage availability and affordability may further decline. A successful 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, 2025, 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 ($493 million as of December 31, 2025). 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, 2025 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. 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, 2025, the estimated fair value of our total derivative assets was $81 million. 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 2027 to 2058 and our gas processing, gathering, and compression services agreements expire at various dates from 2032 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, 2025, our long-term contractual obligations under agreements with minimum volume commitments totaled $8.2 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 2026 production is unchanged from 2025 production, we estimate that we will incur annual net marketing costs of $0.02 per Mcfe to $0.05 per Mcfe in 2026 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 not achieve the intended benefits of the HG Acquisition, and the HG Acquisition may disrupt our existing plans or operations.

There can be no guarantee that we will be able to successfully integrate the assets and operations to be acquired in, or otherwise realize the expected benefits of, the HG Acquisition. Difficulties in integrating the assets acquired in the HG Acquisition may result in operational and other challenges, including the diversion of management's attention from ongoing business concerns; the diversion of resources to integration processes; the retention of existing business and operational relationships, including customers, suppliers and other counterparties; the attraction of new business and operational relationships; the possibility of faulty assumptions underlying expectations regarding integration processes and associated expenses; the elimination of duplicative corporate or operational processes; as well as unanticipated issues in integrating certain systems, including internal controls over financial reporting and disclosure controls and procedures. An inability to realize the full extent of the intended benefits of the HG Acquisition, and any delays encountered in the integration process, could have an adverse effect on our revenues and level of expenses and results of operations. In addition, the integration may result in additional or unforeseen expenses. Although we expect the strategic benefits to offset incremental transaction-related costs over time, if we are not able to adequately and effectively address integration challenges, we may be unable to successfully integrate operations or realize anticipated benefits of the integration.

We may not complete the Utica Shale Divestiture within the anticipated timeframe or at all.

The completion of the Utica Shale Divestiture is subject to a number of conditions. The failure to satisfy all of the required conditions could delay the completion of the Utica Shale Divestiture for a significant period of time or prevent it from occurring at all. A delay in completing the Utica Shale Divestiture could cause us to realize some or all of the benefits later than we otherwise expect to realize them if the Utica Shale Divestiture were successfully completed within the anticipated timeframe, which could result in additional transaction costs or in other negative effects associated with uncertainty around completion of the divestiture.

Notwithstanding the due diligence investigation that we performed in connection with our entry into the definitive agreement to purchase HG Production, HG Production may have liabilities, losses or other exposures for which we do not have adequate insurance coverage or other protection.

While we performed due diligence on HG Production prior to our entry into the definitive agreement to purchase HG Production, we are dependent on the accuracy and completeness of statements and disclosures made or actions taken by HG Production and its representatives when conducting due diligence and evaluating the results of such due diligence. We do not control and may be unaware of activities of HG Production prior to the completion of the HG Acquisition, including intellectual property and other litigation, claims or disputes, information security vulnerabilities, violations of laws, policies, rules and regulations, commercial disputes, tax liabilities and other known and unknown liabilities.

With the consummation of the HG Acquisition, the liabilities of HG Production, including contingent liabilities, will be consolidated with our liabilities for purposes of financial reporting. HG Production may have unknown liabilities which we will be responsible for following the consummation of the HG Acquisition. If HG Production's liabilities are greater than expected, or if there are obligations of HG Production of which we are not aware, our business could be materially and adversely affected. We do not have indemnification rights from the current owners of HG Production for defects and liabilities associated with the acquired assets and instead will rely on a limited representation and warranty insurance policy, which we have obtained. Such insurance is subject to exclusions, policy limits and certain other customary terms and conditions. If we are responsible for liabilities not covered by representation and warranty insurance, we could suffer consequences that could have a material adverse effect on our financial condition and results of operations.

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.

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 2025 included drilling and completion costs of $685 million and leasehold expenditures of $129 million. Our capital budget for 2026 is $1.1 billion to $1.3 billion and includes: $1.0 billion for drilling and completions, $100 million for leasehold expenditures and up to $200 million for discretionary growth capital that is dependent on commodity prices. Our capital budget reflects the closing of the HG Acquisition on February 3, 2026 and assumes the closing of the Utica Shale Divestiture during February 2026. We do not budget for 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.

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
- availability under the Credit Facility.

If our revenues 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, the Term Loan A Facility and our Senior 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.

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 Credit Facility, the Term Loan A Facility or the Senior Notes. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital and credit markets, including the markets for debt securities and credit facilities, 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 Credit Facility, the Term Loan A Facility and certain of the indentures governing our Senior 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, could result in more onerous restrictions in our debt securities and facilities 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. Our debt documents 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.

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 senior note issuers. Our development plan may require access to the capital and credit markets. Although the market for senior note debt securities has improved compared to 2020, if the senior note 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 and the Term Loan A Facility contain 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:

- merge, consolidate, liquidate or dissolve;
- grant liens on our property;
- incur certain indebtedness;
- make dividend payments, distributions or equity repurchases; and
- enter into material non-arms'-length transactions with our affiliates.

The indentures governing certain of our Senior Notes contain similar restrictive covenants as well as restrictive covenants that may limit our ability to sell assets and make investments. In addition, the Credit Facility and the Term Loan A Facility require us to maintain a ratio of total indebtedness to capitalization of 65% or less. These restrictions, together with those in the indentures governing our Senior 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, the Credit Facility and the Term Loan A Facility impose on us.

A breach of any covenant in the Credit Facility or the Term Loan A Facility would result in a default under the relevant agreement after any applicable grace periods. A default, if not waived, could result in our inability to access loans under the Credit Facility or acceleration of the indebtedness outstanding under the Credit Facility or the Term Loan A 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 2025, we had average outstanding borrowings under the Credit Facility of $276 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, and likely result in more restrictive covenants being placed on our future indebtedness. 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.

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.

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. 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. For instance, there have been several recent developments regarding the National Environmental Policy Act ("NEPA") regulatory regime. Most recently, following a Trump administration Executive Order, in February 2025, the White House's Council on Environmental Quality ("CEQ") released an interim final rule rescinding its regulations implementing NEPA. Federal agencies have begun the process of preparing their own new or updated NEPA-implementing rules or guidelines, with the first batch of updates released in July 2025. In May 2025, the Supreme Court issued an opinion in Seven County Infrastructure Coalition v. Eagle County emphasizing the "substantial judicial deference" that courts must grant agencies when considering NEPA challenges. In September 2025, CEQ issued new guidance to federal agencies implementing NEPA encouraging them to limit their NEPA reviews, rely more heavily on sponsor-prepared documents, and streamline the NEPA process. The impact of these developments remains unclear at this time, but any disruption in our ability to obtain permits could result in costs that 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. While the Trump administration may make changes to President Biden's environmental and climate change initiatives, we cannot predict what, when, or how the Trump administration may take actions to revise existing environmental laws or regulations, if at all, or the ultimate impact such changes may have on our business. 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 $1,584,648 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 adversely impact demand for oil and gas 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. However, on January 20, 2025, President Trump issued an Executive Order directing agencies to immediately pause the disbursement of funds appropriated through the IRA 2022. The full impact of this Executive Order and related administrative actions is uncertain at this time. In addition, the IRA 2022 imposed the first ever federal fee on the emission of greenhouse gases through a methane emissions charge. The IRA 2022 amended the federal Clean Air Act to impose a fee on the excess 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. On November 12, 2024, the EPA finalized the methane emissions charge rule, however, in February 2025, Congress repealed the rule under the Congressional Review Act. Additionally, under the OBBB, Congress delayed the implementation of the methane emissions charge until 2034. Compliance with the methane emissions charge and other air pollution control and permitting requirements could impose additional costs on our operations and further reduce demand for oil and natural gas. This could decrease demand for oil and gas and consequently adversely affect our business and results of operations. We cannot predict if the Trump administration and/or Congress may take further actions with respect to the IRA 2022 or the methane emissions charge, nor can we predict what, when, or how the new administration or Congress may take actions to rollback or otherwise revise existing laws, rules, or regulations or the ultimate impact such changes may have on our business or results of operations.

Our operations are subject to a series of risks related to climate 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.

Climate risks continue to attract considerable attention in the United States and in foreign countries. In the United States, no comprehensive climate legislation has been implemented at the federal level. 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. 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 December 2023, 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. However, in March 2025, the EPA announced plans to reconsider OOOOb and OOOOc, in line with the Trump administration’s deregulatory agenda. Additionally, in November 2025, the EPA finalized an interim rule extending the compliance deadlines for certain provisions provided in OOOOb and OOOOc. Litigation challenging the EPA’s final interim rule extending such compliance deadlines for new and existing oil and gas sources remains pending. We cannot predict what additional actions the Trump administration may take or how they might affect our business or results of operations. However, 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.

Increasingly, oil and natural gas companies are exposed to litigation risks related to climate risks. We are not currently party to any such litigation, but could be named in future actions making similar claims of liability and, depending on the nature of the claims alleged and other factors, such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Additionally, 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. Certain institutional lenders who provide financing to fossil-fuel energy companies have also become more attentive to lending practices, and some of them may elect in future not to provide funding for oil and natural gas companies, although this trend has been decreasing. To the extent implemented or pursued, such policies and commitments 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. While we cannot predict how or to what extent sustainable lending and investment practices may impact our operations, 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, some states have adopted or are considering adopting laws requiring the disclosure of climate related risks. Lawsuits have been filed challenging the implementation of these laws, but we cannot predict the outcome of these suits at this time. Compliance with these laws, to the extent they are implemented and applicable to us, may result in additional costs related to 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 and could also increase our litigation risks relating to statements alleged to have been made by us or others in our industry regarding climate 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.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives related to climate risks 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, 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.

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.

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 Michael N. Kennedy, our 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") and tax credit carryforwards are limited, we do not generate expected deductions, or tax authorities challenge our tax positions.

As of December 31, 2025, we have U.S. federal and state NOL carryforwards of approximately $960 million and $1.9 billion, respectively, and U.S. federal tax credit carryforwards of $153 million. We have recorded a reserve for uncertain tax positions related to our U.S. federal tax credits of $51 million as of December 31, 2025. 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 and U.S. federal tax credit carryforwards prior to expiration. The state NOL carryforwards expire at various dates from 2026 to 2044 while others have no expiration date. 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 $1.2 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 (the "Code"), or otherwise.

Section 382 and Section 383 of the Code generally impose an annual limitation on the amount of NOL carryforwards and tax credit carryforwards that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382 of the Code). 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 and tax credit carryforwards would be subject to an annual limitation under Section 382 and Section 383 of the Code. Any unused annual limitation may be carried over to later years. Any limitation on our ability to utilize our NOL carryforwards or tax credit 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 applied 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, 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 and tax credit 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 or tax credit carryforwards are subject to future limitation (including due to an ownership change under Section 382 of the Code), 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. It is unclear whether any such 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 such legislation or 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 2025. 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 U.S. Department of the Treasury and the Internal Revenue Service have released proposed regulations and other interpretive guidance relating to the CAMT. Any significant variance from our current interpretation of such regulations and interpretive guidance could result in a change in our analysis of the application of the CAMT to us and its impact on our operations and cash flows.

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"). In the past, there have been proposals to increase 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.

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 Amended and Restated Antero Resources Corporation 2020 Long Term Incentive Plan (the "Amended 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. Any sales in the public market of the common stock issuable upon such conversion could adversely affect prevailing market prices 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 Vice President – IT 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 Vice President – IT 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 Vice President – IT, 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 Vice President – IT 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 Vice President – IT 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 Vice President – IT, Biren Kumar, has more than 17 years of experience serving as a Chief Information Officer ("CIO") or in similar roles, which have included responsibility for managing cybersecurity risk. Mr. Kumar was named Vice President – IT in

2024. Prior to joining Antero, he served as the CIO for several companies, including Dynegy Inc. from 2005 to 2011, Rockwater Energy Solutions Inc. from 2011 to 2014, KLX Inc. from 2014 to 2018 and KLX Energy Services Holdings, Inc. from 2018 to 2021. Mr. Kumar holds a Bachelor of Business Administration in Management Information Systems and a Master of Business Administration from the University of Houston.

Impact of Risks from Cybersecurity Threats

The energy industry's growing reliance on information technology and operational technology to support critical operations, such as energy production, distribution, and management activities, has made it more susceptible to cybersecurity incidents. As a result, the global rise of cybersecurity incidents, whether from intentional attacks or accidental events, poses a significant challenge to our industry. As cybersecurity threats continue to evolve in complexity and scale, it remains an ongoing and increasingly difficult task for the industry to prevent, detect, mitigate, and remediate these incidents.

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 our consolidated financial statements and is incorporated herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

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 6, 2026, our common stock was held by 98 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, 2025 - October 31, 2025	77,515	$ 32.06	2,800	$ 914,497
November 1, 2025 - November 30, 2025	14,560	34.23	—	914,497
December 1, 2025 - December 31, 2025	—	—	—	914,497
Total	92,075	$ 32.40	2,800	

(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.

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Share Repurchase Program

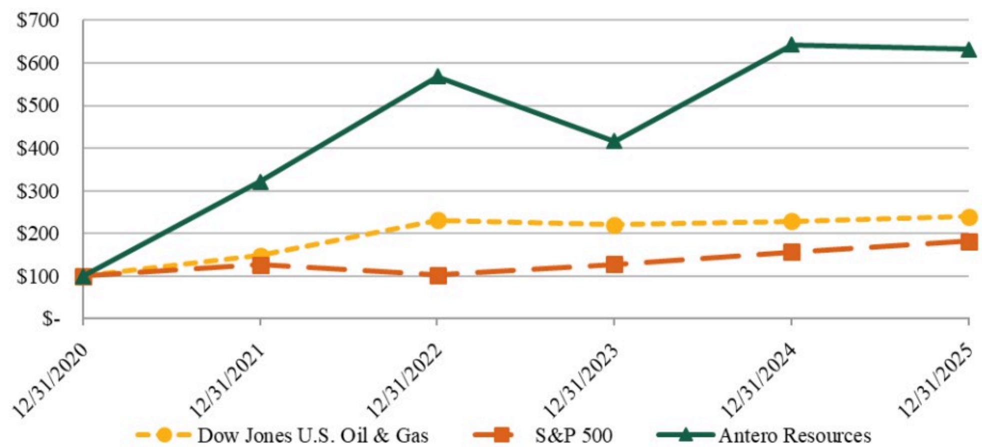
On February 15, 2022, our Board of Directors authorized a share repurchase program to opportunistically repurchase up to $1.0 billion of shares of our outstanding common stock. On October 25, 2022, our Board of Directors authorized a $1.0 billion increase to our share repurchase program to allow us to repurchase up to an aggregate of $2.0 billion of our outstanding common stock. Through December 31, 2025, we have repurchased and retired 32 million shares of our common stock through our share repurchase program at a total cost of $1.1 billion. 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) certain of the indentures relating to our Senior Notes, (iv) the Credit Facility and (v) the Term Loan A 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, 2020 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 have assembled a portfolio of long-lived properties that are characterized by what we believe to be high repeatability and low geologic risk. 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 in the Appalachian Basin. As of December 31, 2025, we held approximately 537,000 net acres in the Appalachian Basin. In addition, we estimate that approximately 168,000 net acres of our leasehold may be prospective for the slightly shallower Upper Devonian Shale.

As of December 31, 2025, our estimated proved reserves were 19.1 Tcfe, consisting of 11.8 Tcf of natural gas, 679 MMBbl of assumed recovered ethane, 529 MMBbl of C3+ NGLs and 23 MMBbl of oil. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2025, we had 1,279 potential horizontal well locations on our existing leasehold acreage that were classified as proved, probable and possible.

We have three reportable segments: exploration and production, our equity method investment in Antero Midstream and marketing. All of our operations are conducted in the United States. See Note 17—Reportable Segments to our consolidated financial statements for additional information.

HG Acquisition

On December 5, 2025, we entered into a definitive agreement to acquire 100% of the issued and outstanding equity interests of HG Production from HG Energy for total cash consideration of $2.8 billion, subject to the terms and conditions thereof. The HG Acquisition includes approximately 385,000 net acres in the core of the Marcellus Shale in West Virginia. Pursuant to the same agreement, Antero Midstream Partners agreed to acquire 100% of the issued and outstanding equity interests of HG Midstream from HG Energy for cash consideration of $1.1 billion, subject to the terms and conditions thereof. The HG Midstream Acquisition includes gathering pipelines and integrated water handling assets in the core of the Marcellus Shale in West Virginia. These acquisitions closed on February 3, 2026. The HG Acquisition was funded with borrowings under the Term Loan A Facility, net proceeds of the 2036 Notes (as defined below), borrowings under the Credit Facility and restricted cash. See Note 3—Transactions to our consolidated financial statements for additional information. We intend to make certain modifications to our existing commercial arrangements with Antero Midstream to provide for on-pad compression with respect to certain wells and to provide a transition period through 2026 before certain water services would be provided under the existing agreements with Antero Midstream.

Utica Shale Divestiture

On December 5, 2025, we entered into a definitive agreement with the Buyer Parties to sell our Utica Shale Properties for aggregate cash consideration of $800 million, subject to the terms and conditions thereof. The Utica Shale Properties include approximately 80,000 gross (70,000 net) acres located in Ohio and proved reserves of approximately 600 Bcfe as of December 31, 2025. The Utica Shale Divestiture is expected to close in February 2026, subject to the satisfaction of certain customary closing conditions. The net proceeds from the Utica Shale Divestiture are expected to be used for the repayment of long-term debt. See Note 3—Transactions to our consolidated financial statements for additional information.

Financing Highlights

Credit Facility Maturity Date Extension

Effective July 30, 2025, we obtained the consent of each of the lenders under our Unsecured Credit Facility to extend the Maturity Date from July 30, 2029 to July 30, 2030. The terms of the Unsecured Credit Facility otherwise remain unchanged. Under the terms of the Unsecured Credit Facility, we may request two one-year extensions of the Maturity Date, subject to the satisfaction of certain conditions. This is the first such extension. See Note 7—Long-Term Debt to our consolidated financial statements for additional information.

Issuance of the 2036 Senior Notes

On January 28, 2026, we issued $750 million of 5.400% senior notes due February 1, 2036 (the "2036 Notes") at a price of 99.869% of par. The 2036 Notes are unsecured and rank pari passu to our Unsecured Credit Facility and Term Loan A Facility and other outstanding senior notes. The 2036 Notes are not guaranteed by any of our subsidiaries. The net proceeds from this offering were used to partially fund the HG Acquisition. See Note 3—Transactions and Note 7—Long-Term Debt to our consolidated financial statements for additional information.

Notice of Redemption of 2029 Notes

On February 9, 2026, we notified the holders of our 7.625% senior notes due February 1, 2029 (the "2029 Notes") of our intent to redeem all $365 million aggregate principal amount of our 2029 Notes on February 24, 2026, subject to certain conditions, including the closing of the Utica Shale Divestiture, at a redemption price of 101.271%, plus accrued and unpaid interest.

Term Loan A

On February 3, 2026, substantially concurrently with the consummation of the HG Acquisition, we entered into an unsecured three year term loan facility in an aggregate principal amount of $1.5 billion with the Royal Bank of Canada, RBC Capital Markets and JPMorgan Chase Bank, N.A. (collectively, the "Banks"). Borrowings are unsecured and are not guaranteed by any of our subsidiaries. On February 3, 2026, we borrowed $1.5 billion in a single borrowing to partially fund the HG Acquisition. The Term Loan A Facility is scheduled to mature on February 3, 2029. See Note 3—Transactions and See Note 7—Long-Term Debt to our consolidated financial statements for additional information.

Debt Repurchase Program

During the year ended December 31, 2025, we redeemed the remaining $97 million aggregate principal amount of our 8.375% senior notes due July 15, 2026 (the "2026 Notes") at a redemption price of 102.094% of the principal amount thereof, plus accrued and unpaid interest. In addition, we repurchased $42 million aggregate principal amount of our 2029 Notes through open market transactions at a weighted average price of approximately 103% of the principal amount thereof, plus accrued and unpaid interest. See Note 7—Long-Term Debt to our consolidated financial statements for additional information.

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. Through our share repurchase program, during the year ended December 31, 2025, we repurchased and retired approximately 4 million shares of our common stock at a total cost of $136 million. As of December 31, 2025, we have approximately $914 million of capacity 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.

Market Conditions and Business Trends

Commodity Markets

Prices for natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Benchmark prices for natural gas and ethane increased significantly, while benchmark prices for C3+ NGLs and oil decreased, during the year ended December 31, 2025 as compared to the year ended December 31, 2024. As a result of the higher benchmark natural gas and ethane prices during the year ended December 31, 2025, we experienced an increase in price realization for natural gas and ethane products, partially offset by the effects of decreased benchmark NGLs and oil prices as compared to the year ended December 31, 2024. 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, Venezuela 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. However, we use derivative instruments when circumstances warrant to manage our exposure to commodity price risk. See "—Hedge Position" and Note 11—Derivative Instruments to our consolidated financial statements for additional information on our derivative instruments.

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

	Year Ended December 31,	
	2024	2025
Henry Hub ($/Mcf) (1)	$ 2.27	3.43
Mont Belvieu Ethane ($/Bbl) (2)	8.00	10.61
Mont Belvieu C3+ NGLs ($/Bbl) (3)	40.82	37.93
West Texas Intermediate ($/Bbl) (4)	75.72	64.81

(1) NYMEX first of month average natural gas price.
(2) ICE settlement ethane OPIS futures average price for the front month contract as published on the last trading day of the month.
(3) ICE settlement propane, isobutane, normal butane and natural gasoline OPIS futures average price for the front month contract as published on the last trading day of the month. Propane and isobutane reflect TET prices, and normal butane and natural gasoline reflect non-TET prices. Propane, isobutane, normal butane and natural gasoline futures prices are weighted to approximate Antero Resources' average C3+ NGLs composition.
(4) NYMEX calendar month average settled futures price.

Hedge Position

Antero Resources

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. For the years ended December 31, 2024 and 2025, 4% and 8%, respectively, of our production was hedged through commodity derivatives. Assuming our 2026 production is the same as our production in 2025, approximately 42% of our total production is hedged through commodity derivatives. In addition, we also have derivative contracts in place for a portion of our 2027 production. As of December 31, 2025, the estimated fair value of our commodity derivative contracts was a net asset of $81 million. See Note 11—Derivative Instruments to our consolidated financial statements for additional information.

Martica

Our consolidated VIE, Martica, previously maintained 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 were fully attributable to the noncontrolling interests in Martica. During the three months ended March 31, 2025, all of Martica's derivative contracts expired. As of December 31, 2025, Martica had no derivative instruments. See Note 11—Derivative Instruments to our consolidated financial statements for additional 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 2024. 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 2022 in an effort to bring the inflation rate in line with its stated goal of 2% on a long-term basis. Between 2022 and 2023, the Federal Reserve increased the federal funds interest rate by 5.25%. During the second half of 2024, inflation rates began to approach the Federal Reserve's stated goal of 2%, and the Federal Reserve decreased the federal funds rate by 1.75% in 2024 and 2025. While inflationary pressures in the United States' economy have begun to subside, it is uncertain what impact recent tariff activity by the United States and foreign governments will have on inflation. See "—Results of Operations" for additional 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, tariffs, other global trade restrictions and conflicts, including those in the Middle East, Iran and Venezuela, among others. While our supply chain has not experienced any significant interruptions as a result of such events, there can be no assurance that we will not experience interruptions in the future.

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 2024 and 2025, our production revenues were comprised of 44% and 57%, respectively, from the sale of natural gas and 56% and 43%, 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 our production when circumstances warrant. We currently utilize call and embedded put options, basis swap contracts that hedge the difference between the NYMEX index price and a local index price, collar contracts and fixed price contracts for a portion of our natural gas in which we receive or pay the difference between a fixed price and the variable market price received. Assuming our 2026 production is the same as our production in 2025, approximately 42% of our total production for 2026 is hedged through commodity derivatives. In addition, we have derivative contracts in place for a portion of our 2027 production. See Note 11—Derivative Instruments to our consolidated financial statements for additional information. At the end of each accounting period, we estimate the fair value of these derivative instruments, and 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 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.

- *Impairment of property and equipment.* These costs include impairment and costs associated with lease 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 our consolidated financial statements for additional 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 the Adjusted Term SOFR Rate, the Adjusted Daily Simple SOFR (collectively, "SOFR") or the Alternate Base Rate, in each case, plus an Applicable Rate (each term as defined in the Credit Facility). As of December 31, 2024 and 2025, we had an outstanding balance on the Credit Facility of $393 million and $439 million, respectively, with a weighted average interest rate of 5.9% and 5.3%, respectively. 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, 2024 and 2025, we had fixed interest rates on our Senior Notes ranging from 5.375% to 8.375% and 5.375% to 7.625%, respectively, with an aggregate principal balance of $1.1 billion and $1.0 billion, respectively. See Note 7—Long-Term Debt to our consolidated financial statements for additional information.

- *Income tax (expense) benefit.* We are subject to U.S. federal and state 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) benefit 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, the deferral of unsettled commodity derivative gains and losses for tax purposes until they are settled and research and development ("R&D") tax credits. We have recorded 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. See Note 13—Income Taxes to our consolidated financial statements for additional information.

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Results of Operations

We have three reportable segments: exploration and production, our equity method investment in Antero Midstream and marketing. 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 our consolidated financial statements for additional information.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2025

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

	Year Ended December 31, 2024				
	Exploration and Production	**Marketing**	**Equity Method Investment in Antero Midstream (1)**	**Elimination of Unconsolidated Affiliate**	**Consolidated Total**
Revenue and other:					
Natural gas sales	$ 1,818,297	—	—	—	1,818,297
Natural gas liquids sales	2,066,975	—	—	—	2,066,975
Oil sales	230,027	—	—	—	230,027
Commodity derivative fair value gains	731	—	—	—	731
Gathering, compression and water handling	—	—	1,106,193	(1,106,193)	—
Marketing	—	179,069	—	—	179,069
Amortization of deferred revenue, VPP	27,101	—	—	—	27,101
Other revenue and income	3,396	—	—	—	3,396
Total revenue	4,146,527	179,069	1,106,193	(1,106,193)	4,325,596
Operating expenses:					
Lease operating	118,693	—	—	—	118,693
Gathering and compression	897,160	—	103,053	(103,053)	897,160
Processing	1,069,887	—	—	—	1,069,887
Transportation	735,883	—	—	—	735,883
Water handling	—	—	114,923	(114,923)	—
Production and ad valorem taxes	207,671	—	—	—	207,671
Marketing	—	244,906	—	—	244,906
Exploration	2,618	—	—	—	2,618
General and administrative (excluding equity-based compensation)	162,876	—	41,754	(41,754)	162,876
Equity-based compensation	66,462	—	44,332	(44,332)	66,462
Depletion, depreciation and amortization	762,068	—	140,000	(140,000)	762,068
Impairment of property and equipment	47,433	—	332	(332)	47,433
Accretion of asset retirement obligations	3,759	—	—	—	3,759
Loss on sale of assets	862	—	—	—	862
Contract termination, loss contingency, settlements and other operating expenses	4,858	—	2,633	(2,633)	4,858
Total operating expenses	4,080,230	244,906	447,027	(447,027)	4,325,136
Operating income (loss)	$ 66,297	(65,837)	659,166	(659,166)	460
Equity in earnings of unconsolidated affiliates	$ 93,787	—	110,573	(110,573)	93,787

(1) Amounts reflect those recorded in Antero Midstream Corporation's consolidated financial statements.

	Year Ended December 31, 2025				
	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream [(1)]	Elimination of Unconsolidated Affiliate	Consolidated Total
Revenue and other:					
Natural gas sales	$ 2,873,241	—	—	—	2,873,241
Natural gas liquids sales	1,986,840	—	—	—	1,986,840
Oil sales	150,158	—	—	—	150,158
Commodity derivative fair value gains	111,049	—	—	—	111,049
Gathering, compression and water handling	—	—	1,188,426	(1,188,426)	—
Marketing	—	125,900	—	—	125,900
Amortization of deferred revenue, VPP	25,264	—	—	—	25,264
Other revenue and income	3,371	—	—	—	3,371
Total revenue	5,149,923	125,900	1,188,426	(1,188,426)	5,275,823
Operating expenses:					
Lease operating	135,124	—	—	—	135,124
Gathering and compression	946,900	—	107,846	(107,846)	946,900
Processing	1,125,358	—	—	—	1,125,358
Transportation	785,168	—	—	—	785,168
Water handling	—	—	124,064	(124,064)	—
Production and ad valorem taxes	163,135	—	—	—	163,135
Marketing	—	190,206	—	—	190,206
Exploration	2,990	—	—	—	2,990
General and administrative (excluding equity-based compensation)	171,714	—	41,976	(41,976)	171,714
Equity-based compensation	60,812	—	45,958	(45,958)	60,812
Depletion, depreciation and amortization	749,675	—	134,310	(134,310)	749,675
Impairment of property and equipment	29,358	—	984	(984)	29,358
Accretion of asset retirement obligations	3,892	—	—	—	3,892
Gain on sale of assets	(266)	—	—	—	(266)
Loss on long-lived assets	—	—	86,626	(86,626)	—
Contract termination, loss contingency, settlements and other operating expenses	28,111	—	1,993	(1,993)	28,111
Total operating expenses	4,201,971	190,206	543,757	(543,757)	4,392,177
Operating income (loss)	$ 947,952	(64,306)	644,669	(644,669)	883,646
Equity in earnings of unconsolidated affiliates	$ 98,484	—	116,439	(116,439)	98,484

(1) Amounts reflect those recorded in Antero Midstream Corporation's consolidated financial statements.

Exploration and Production Segment

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

	Year Ended December 31, 2024	Year Ended December 31, 2025	Amount of Increase (Decrease)	Percent Change
Production data [1] [2]:				
Natural gas (Bcf)	793	808	15	2 %
C2 Ethane (MBbl)	30,391	29,842	(549)	(2)%
C3+ NGLs (MBbl)	42,434	42,010	(424)	(1)%
Oil (MBbl)	3,693	2,899	(794)	(22)%
Combined (Bcfe)	1,252	1,256	4	*
Daily combined production (MMcfe/d)	3,421	3,442	21	1 %
Average prices before effects of derivative settlements [3]:				
Natural gas (per Mcf)	$ 2.29	3.56	1.27	55 %
C2 Ethane (per Bbl) [4]	$ 9.05	11.91	2.86	32 %
C3+ NGLs (per Bbl)	$ 42.23	38.83	(3.40)	(8)%
Oil (per Bbl)	$ 62.29	51.80	(10.49)	(17)%
Weighted Average Combined (per Mcfe)	$ 3.29	3.99	0.70	21 %
Average realized prices after effects of derivative settlements [3]:				
Natural gas (per Mcf)	$ 2.30	3.54	1.24	54 %
C2 Ethane (per Bbl) [4]	$ 9.05	11.91	2.86	32 %
C3+ NGLs (per Bbl)	$ 42.36	38.83	(3.53)	(8)%
Oil (per Bbl)	$ 62.15	51.76	(10.39)	(17)%
Weighted Average Combined (per Mcfe)	$ 3.30	3.97	0.67	20 %
Average costs (per Mcfe):				
Lease operating	$ 0.09	0.11	0.02	22 %
Gathering and compression	$ 0.72	0.75	0.03	4 %
Processing	$ 0.85	0.90	0.05	6 %
Transportation	$ 0.59	0.62	0.03	5 %
Production and ad valorem taxes	$ 0.17	0.13	(0.04)	(24)%
Marketing expense, net	$ 0.05	0.05	—	*
General and administrative (excluding equity-based compensation)	$ 0.13	0.14	0.01	8 %
Depletion, depreciation, amortization and accretion	$ 0.61	0.60	(0.01)	(2)%

* Not meaningful
(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, 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, 2024 and 2025 includes $2 million and $1 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, 2024 and 2025 would have been $8.99 per Bbl and $11.88 per Bbl, respectively.

Natural gas sales. Revenues from sales of natural gas increased from $1.8 billion for the year ended December 31, 2024 to $2.9 billion for the year ended December 31, 2025, an increase of $1.1 billion, or 58%. Higher commodity prices (excluding the effects of derivative settlements) during the year ended December 31, 2025 accounted for an approximate $1.0 billion increase in year-over-year natural gas sales revenue (calculated as the change in the year-to-year average price times current year production volumes). Higher natural gas production volumes accounted for an approximate $34 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 $2.1 billion for the year ended December 31, 2024 to $2.0 billion for the year ended December 31, 2025, a decrease of $0.1 billion, or 4%. Lower C3+ NGLs commodity prices (excluding the effects of derivative settlements) during the year ended December 31, 2025 accounted for an approximate $143 million decrease in year-over-year NGLs revenues (calculated as the change in the year-to-year average price times current year production volumes), partially offset by higher ethane commodity prices during the year ended December 31, 2025 that accounted for an approximate $85 million increase in year-over-year NGLs revenues (calculated as the change in the year-to-year average price times current year production volumes). Lower NGLs production volumes during the year ended December 31, 2025 accounted for an approximate $23 million decrease 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 $230 million for the year ended December 31, 2024 to $150 million for the year ended December 31, 2025, a decrease of $80 million, or 35%. Lower oil production volumes during the year ended December 31, 2025 accounted for an approximate $50 million decrease in year-over-year oil revenues (calculated as the change in year-to-year volumes times the prior year average price). Lower oil prices for the year ended December 31, 2025 (excluding the effects of derivative settlements) accounted for an approximate $30 million decrease in year-over-year oil revenues (calculated as the change in the year-to-year average price times current year production volumes).

Commodity derivative fair value gains. 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. For the years ended December 31, 2024 and 2025, our commodity hedges resulted in derivative fair value gains of $1 million and $111 million, respectively. For the year ended December 31, 2024, commodity derivative fair value gains included $10 million of net cash proceeds for settled derivative gains. For the year ended December 31, 2025, commodity derivative fair value gains included $17 million of net cash payments for settled derivative losses.

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, 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.

Amortization of deferred revenue, VPP. Amortization of deferred revenues associated with the VPP decreased from $27 million for the year ended December 31, 2024 to $25 million for the year ended December 31, 2025, a decrease of $2 million or 7%, 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 $119 million, or $0.09 per Mcfe, for the year ended December 31, 2024 to $135 million, or $0.11 per Mcfe, for the year ended December 31, 2025, an increase of $16 million primarily due to increased produced water volumes and trucking and disposal costs as a result of our completion activity timing during the year ended December 31, 2025, as well as higher oilfield service and workover costs between periods.

Gathering, compression, processing and transportation expense. Gathering, compression, processing and transportation expense increased from $2.7 billion for the year ended December 31, 2024 to $2.9 billion for the year ended December 31, 2025, an increase of $0.2 billion, or 6%. This fluctuation was primarily a result of the following:

- Gathering and compression costs on a per unit basis increased from $0.72 per Mcfe for the year ended December 31, 2024 to $0.75 per Mcfe for the year ended December 31, 2025, primarily due to increased fuel costs as a result of higher natural gas prices and annual CPI-based adjustments between periods.

- Processing costs on a per unit basis increased from $0.85 per Mcfe for the year ended December 31, 2024 to $0.90 per Mcfe for the year ended December 31, 2025, primarily due to increased costs for NGLs processing and transportation, which includes an annual CPI-based adjustment during the first quarter of 2025, and higher NGLs transportation fees between periods.

- Transportation costs on a per unit basis increased from $0.59 per Mcfe for the year ended December 31, 2024 to $0.62 per Mcfe for the year ended December 31, 2025, primarily due to higher fuel costs as a result of higher natural gas prices between periods and higher demand fees for certain pipelines during the year ended December 31, 2025.

Production and ad valorem tax expense. Production and ad valorem taxes decreased from $208 million for the year ended December 31, 2024 to $163 million for the year ended December 31, 2025, a decrease of $45 million or 21%, primarily due to lower ad valorem taxes of $115 million between periods, partially offset by higher severance taxes of $70 million as a result of increased natural gas prices during the year ended December 31, 2025. Production and ad valorem taxes as a percentage of natural gas revenues decreased from 11% for the year ended December 31, 2024 to 6% for the year ended December 31, 2025, primarily as a result of lower ad valorem taxes between periods. West Virginia ad valorem taxes in 2024 were based on commodity prices during 2022, and West Virginia ad valorem taxes in 2025 are based on commodity prices during 2023.

General and administrative expense. General and administrative expense (excluding equity-based compensation expense) increased from $163 million for the year ended December 31, 2024 to $172 million for the year ended December 31, 2025, an increase of $9 million, or 5%, primarily due to higher professional service fees and increased salary and wage expense as a result of increased employee headcount between periods. We had 616 and 632 employees as of December 31, 2024 and 2025, respectively. General and administrative expense on a per unit basis (excluding equity-based compensation) increased from $0.13 per Mcfe for the year ended December 31, 2024 to $0.14 per Mcfe for the year ended December 31, 2025 primarily as a result of higher overall costs between periods.

Equity-based compensation expense. Non-cash equity-based compensation expense decreased from $66 million for the year ended December 31, 2024 to $61 million for the year ended December 31, 2025, a decrease of $5 million or 9%. This decrease was primarily due to lower performance share unit ("PSU") award grants between periods. See Note 9—Equity-Based Compensation to our consolidated financial statements for additional information.

Depletion, depreciation and amortization expense. DD&A expense decreased from $762 million for the year ended December 31, 2024 to $750 million for the year ended December 31, 2025, a decrease of $12 million or 2%, primarily as a result of increased proved reserve volumes due to higher commodity prices. DD&A expense per Mcfe remained relatively consistent for the years ended December 31, 2024 and 2025 at $0.61 and $0.60, respectively.

Impairment of property and equipment. Impairment of property and equipment decreased from $47 million for the year ended December 31, 2024 to $29 million for the year ended December 31, 2025, a decrease of $18 million, or 38%, primarily due to lower impairments of expiring leases between periods as a result of our maintenance capital program. 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 utilize.

Contract termination, loss contingency, settlements and other operating expenses. Contract termination, loss contingency, settlements and other operating expenses attributable to our exploration and production segment increased from $5 million for the year ended December 31, 2024 to $28 million for the year ended December 31, 2025, an increase of $23 million. This increase was primarily due to loss contingencies recorded during the year ended December 31, 2025. See Note 15—Contingencies to our consolidated financial statements for additional information.

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 remained relatively consistent at $66 million, or $0.05 per Mcfe, for the year ended December 31, 2024 and $64 million, or $0.05 per Mcfe, for the year ended December 31, 2025.

Marketing revenue. Marketing revenue decreased from $179 million for the year ended December 31, 2024 to $126 million for the year ended December 31, 2025, a decrease of $53 million, or 30%. This fluctuation primarily resulted from the following:

- Natural gas marketing revenue decreased by $18 million between periods primarily due to lower natural gas marketing volumes, partially offset by higher natural gas prices. Lower natural gas marketing volumes accounted for a $24 million decrease in year-over-year marketing revenues (calculated as the change in year-to-year volumes times the prior year average price), and higher natural gas prices accounted for a $6 million increase in year-over-year marketing revenues (calculated as the change in the year-to-year average price times current year marketing volumes).

- Oil marketing revenue decreased by $53 million between periods primarily due to lower oil marketing volumes and prices. Lower oil marketing volumes accounted for a $31 million decrease 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 $22 million decrease in year-over-year marketing revenues (calculated as the change in the year-to-year average price times current year marketing volumes).

- NGLs marketing revenue increased by $8 million between periods primarily due to higher ethane and C3+ NGLs marketing volumes and higher ethane prices.

Marketing expense. Marketing expense decreased from $245 million for the year ended December 31, 2024 to $190 million for the year ended December 31, 2025, a decrease of $55 million, or 22%. 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 commodity purchases decreased by $60 million between periods primarily due to lower marketing volumes and oil prices between periods, partially offset by higher natural gas prices during the year ended December 31, 2025. Firm transportation costs increased $5 million between periods primarily due to the increase in fuel costs and lower pipeline utilization due to maintenance during the year ended December 31, 2025.

Equity Method Investment in Antero Midstream Segment

Antero Midstream revenue. Revenue from the Antero Midstream segment increased from $1.1 billion for the year ended December 31, 2024 to $1.2 billion for the year ended December 31, 2025, an increase of $0.1 billion. This increase is primarily due to higher gathering and processing revenues of $61 million and higher water handling revenues of $21 million. The increased gathering and processing revenues between periods is primarily a result of increased throughput and annual CPI-based gathering and compression rate adjustments between periods. The increased water handling revenues between periods is primarily due to higher wastewater trucking and blending volumes, increased wastewater trucking and disposal costs that are billed at cost plus 3% higher fresh water delivery volumes and increased blending cost of service fees during the year ended December 31, 2025, as well as an increase to the fresh water delivery rate as a result of the annual CPI-based rate adjustment between periods.

Antero Midstream operating expense. Total operating expense related to the Antero Midstream segment increased from $447 million for the year ended December 31, 2024 to $544 million for the year ended December 31, 2025, an increase of $97 million. This increase is primarily due to a loss on long-lived assets of $87 million related to the expected divestiture of its Utica Shale midstream assets, higher direct operating expenses of $14 million as a result of higher wastewater trucking and disposal costs, increased blending costs, increased fresh water delivery volumes, increased throughput, higher gathering and compression costs for assets acquired during the second quarter of 2024 and increased heavy maintenance expense during the year ended December 31, 2025, partially offset by lower depreciation expense of $5 million related to Antero Midstream's program to repurpose underutilized compressor units to expand existing or construct new compressor stations between periods, partially offset by assets placed in service between periods.

Items Not Allocated to Segments

Interest expense. Interest expense decreased from $118 million for the year ended December 31, 2024 to $84 million for the year ended December 31, 2025, a decrease of $34 million or 29%, primarily due to the redemption or repurchase of $139 million aggregate principal amount of our 2026 Notes and 2029 Notes, as well as lower average Credit Facility borrowings and interest rates during the year ended December 31, 2025.

Loss on early extinguishment of debt. During the year ended December 31, 2024, we recognized a loss on early debt extinguishment of $1 million related to the amendment and restatement of our senior revolving credit facility. During the year ended December 31, 2025, we recognized a loss on early debt extinguishment of $4 million related to the redemption of the remaining $97 million aggregate principal amount of our 2026 Notes at a redemption price of 102.094% of the principal amount thereof, plus accrued and unpaid interest, and the repurchase of $42 million aggregate principal amount of our 2029 Notes through open market transactions at a weighted average price of approximately 103% of the principal amount thereof, plus accrued and unpaid interest. See Note 7—Long-Term Debt to our consolidated financial statements for additional information.

Transaction expense. There were no transaction expenses incurred during the year ended December 31, 2024. During the year ended December 31, 2025, we incurred $4 million of transaction expense related to the HG Acquisition. See Note 3—Transactions to our consolidated financial statements for additional information.

Income tax (expense) benefit. For the year ended December 31, 2024, we recognized an income tax benefit of $118 million primarily due to R&D tax credits of $95 million, loss before income taxes of $24 million and a reduction to our state NOL carryforward valuation allowance of $12 million. For the year ended December 31, 2025, we recognized income tax expense of $216 million, with an effective tax rate of 24%, related to our income before income taxes of $890 million. Our effective tax rate for the year ended December 31, 2025 was different than the federal statutory rate of 21% primarily due to the effects of state income taxes, equity-based compensation expenses, dividends received deduction and noncontrolling interests. See Note 13—Income Taxes to our consolidated financial statements for additional information.

As of December 31, 2025, we had U.S. federal and state NOL carryforwards of approximately $960 million and $1.9 billion, respectively. Many of these NOL carryforwards expire at various dates between 2026 and 2044 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, 2023 Compared to Year Ended December 31, 2024

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, 2024 for a discussion of the results of operations for the year ended December 31, 2023 compared to the year ended December 31, 2024.

Capital Resources and Liquidity

Overview

Our primary sources of liquidity have been through net cash provided by operating activities, borrowings under our Credit Facility, our Term Loan A Facility, issuances of debt and equity securities and additional contributions from our asset sales, including our drilling partnerships. 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.

Our commodity hedge position can provide us with liquidity for the portion of our production that is hedged because it provides us with the relative certainty of our future expected revenues for such production despite potential declines in the price of natural gas. Assuming our 2026 production is the same as our production in 2025, approximately 42% of our total production for 2026 is hedged through commodity derivatives. Our ability to make significant acquisitions for cash would require us to utilize borrowings under 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 13 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.

Capital Spending and 2026 Capital Budget

For the year ended December 31, 2025, our total consolidated capital expenditures were $797 million, including drilling and completion expenditures of $658 million, leasehold additions of $131 million and other capital expenditures of $8 million. We completed 61 net horizontal wells during the year ended December 31, 2025. Our capital budget for 2026 is $1.1 billion to $1.3 billion and includes: $1.0 billion for drilling and completions, $100 million for leasehold expenditures and up to $200 million for discretionary growth capital that is dependent on commodity prices. Our capital budget reflects the closing of the HG Acquisition on February 3, 2026 and assumes the closing of the Utica Shale Divestiture during February 2026. We do not budget for acquisitions. During 2026, we plan to complete 70 to 80 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, 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, 2025, we believe that net cash provided from operating activities and available borrowings under the Credit Facility, the net proceeds of the offering of the 2036 Notes, borrowings under the Term Loan A Facility and net proceeds from the Utica Shale Divestiture 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 Note 7—Long-Term Debt to our consolidated financial statements.

See Note 14—Commitments to our 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,	
	2024	2025
Net cash provided by operating activities	$ 849,288	1,630,930
Net cash used in investing activities	(714,153)	(1,077,813)
Net cash used in financing activities	(135,135)	(343,117)
Net increase in cash, cash equivalents and restricted cash	$ —	210,000

Year Ended December 31, 2024 Compared to Year Ended December 31, 2025

Operating activities. Net cash provided by operating activities was $0.8 billion and $1.6 billion for the years ended December 31, 2024 and 2025, respectively. Net cash provided by operating activities increased between periods primarily due to higher natural gas revenues, lower ad valorem taxes, lower interest expense and changes in working capital, partially offset by lower NGLs and oil revenues, higher lease operating expense and higher gathering, compression, processing and transportation expense during the year ended December 31, 2025.

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 $0.7 billion for the year ended December 31, 2024 to $1.1 billion for the year ended December 31, 2025, primarily due to asset acquisitions of $253 million of during the year ended December 31, 2025 and increased drilling and completions and leasing activity of $71 million and $38 million, respectively, between periods, partially offset by higher proceeds from asset sales of $7 million between periods primarily due to oil and gas property trades during the year ended December 31, 2025. The increase in our drilling and completions activity is primarily due to completing 20 additional net wells between periods.

Financing activities. Net cash used in financing activities increased from $135 million for the year ended December 31, 2024 to $343 million for the year ended December 31, 2025, primarily due to redemptions and repurchases of our Senior Notes of $142 million during the year ended December 31, 2025, share repurchases of $136 million during the year ended December 31, 2025, net borrowings on our Credit Facility of $45 million during the year ended December 31, 2025 and higher payment of debt issuance costs for our Unsecured Credit Facility of $3 million, partially offset by lower distributions to the noncontrolling interests in Martica of $4 million between periods and net repayments on our Credit Facility of $24 million during the year ended December 31, 2024.

Year Ended December 31, 2023 Compared to Year Ended December 31, 2024

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, 2024 for a discussion of the cash flows for the year ended December 31, 2023 compared to the year ended December 31, 2024.

Debt Agreements

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. We were in compliance with all covenants and ratios applicable to our debt agreements as of December 31, 2024 and 2025. See Note 7—Long-Term Debt to our consolidated financial statements for additional information.

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 $51 million, $47 million and $29 million for the years ended December 31, 2023, 2024 and 2025, 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, 2023, 2024 and 2025.

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 6% and 20%, respectively, from year end 2025 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, 2025, 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 are 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 U.S. federal income taxes, but are currently not in a cash tax paying position with respect to U.S. federal income taxes.

We record a valuation allowance or reserve for an uncertain tax position 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 or our tax credits can be utilized. 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, 2025, we have recognized a valuation allowance of $39 million related to Colorado and Oklahoma state NOL carryforwards that we do not expect to realize due to expected future reduced income tax apportionment in those states. In addition, as of December 31, 2025, we have recorded a reserve for uncertain tax positions of $51 million related to our R&D tax credits.

The calculation of deferred income tax assets and liabilities involves uncertainties in the application of complex tax laws and regulations, as well as judgement on the amount of financial statement benefit recorded for uncertain tax positions. We recognize in our financial statements those tax positions which we believe are more-likely-than-not to be sustained upon examination by the IRS or state revenue authorities. We believe that the estimates and assumptions related to income taxes are critical because of 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 judgement required to determine the amount and timing of a valuation allowance on our deferred income tax assets and reserve for uncertain tax positions. These assumptions affect deferred income tax liability and income tax (expense) benefit 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. For the years ended December 31, 2024 and 2025, 4% and 8%, respectively, of our production was hedged through commodity derivatives.

Our financial hedging activities may include commodity derivative instruments that are intended to support natural gas, NGLs and oil prices at targeted levels and to manage our exposure to price risk associated with our production. These contracts may include commodity price swaps whereby we will receive a fixed price and pay a variable market price to the contract counterparty, collars that set a floor and ceiling price for the hedged production, basis differential swaps or call or embedded put options, among others. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. As of December 31, 2025, our commodity derivatives included fixed swaps, basis swaps, collars, 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 additional information.

Based on our production and our derivative instruments that settled during the year ended December 31, 2025, our revenues would have decreased by $145 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, 2025.

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. 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) in the consolidated statements of operations and comprehensive income.

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, 2024, the estimated fair value of our commodity derivative instruments was a net liability of $47 million, comprised of current and noncurrent assets and liabilities. As of December 31, 2025, the estimated fair value of our commodity derivative instruments was a net asset of $81 million, comprised of current and noncurrent assets.

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 ($493 million as of December 31, 2025), which we market to energy companies, end users and refineries, and commodity derivative contracts ($81 million as of December 31, 2025).

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. While we do at times require customers to post letters of credit or other credit support in connection with their obligations, 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. As of December 31, 2025, we have commodity hedges in place with eight different counterparties, seven of which are lenders under the Unsecured Credit Facility. We had derivative assets of $81 million with bank counterparties under our Unsecured Credit Facility as of December 31, 2025. 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, 2025. We believe that all of the counterparties to our derivative instruments are acceptable credit risks as of December 31, 2025. 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, 2025, 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, 2025 was 5.9%. We estimate that a 1.0% increase in the applicable average interest rates for the year ended December 31, 2025 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, 2025 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, 2025 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, 2025.

The effectiveness of our internal control over financial reporting as of December 31, 2025 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

In connection with the HG Acquisition, we entered into a letter agreement with Antero Midstream Partners to, among other things, allocate between the parties certain obligations, liabilities, costs and benefits under the purchase agreement relating to the HG Acquisition and the buyer-side representations and warranties insurance policies. A copy of the Letter Agreement is filed as Exhibit 10.29 hereto and is incorporated herein by reference.

On November 6, 2025, Michael N. Kennedy, our Chief Executive Officer and President and Director, adopted a "Rule 10b5-1 trading arrangement," as defined in Item 408(a) of Regulation S-K, that is intended to satisfy the affirmative defense of Rule 10b5-1(c) for the sale of up to 200,000 shares of the Company's common stock until December 31, 2026.

On November 6, 2025, Benjamin A Hardesty, our Chairman of the Board, adopted a "Rule 10b5-1 trading arrangement," as defined in Item 408(a) of Regulation S-K, that is intended to satisfy the affirmative defense of Rule 10b5-1(c) for the sale of up to 48,000 shares of the Company's common stock until December 31, 2026.

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 2026 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 2026 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 2026 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 2026 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 2026 Annual Meeting of Stockholders.

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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	Third Amended and Restated Bylaws of Antero Resources Corporation, dated August 14, 2025 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on August 14, 2025).
4.1	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).
4.2	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).
4.3	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).
4.4*	Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended.
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	Base Indenture, dated January 28, 2026, among Antero Resources Corporation and Computershare Trust Company, N.A., 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 28, 2026).
4.10	First Supplemental Indenture, dated January 28, 2026, among Antero Resources Corporation and Computershare Trust Company, N.A., as trustee (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 28, 2026).

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Exhibit Number	Description of Exhibit
10.1	Contribution Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero 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 Agreement, 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†	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).
10.14	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).
10.15	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).
10.16†	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).

Exhibit Number	Description of Exhibit
10.17†	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).
10.18†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the Amended and Restated 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 April 30, 2025).
10.19†	Amended and Restated Antero Resources Corporation 2020 Long Term Incentive Plan, dated June 5, 2024 (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 6, 2024).
10.20	Amended and Restated Credit Agreement, dated as of July 30, 2024, among Antero Resources Corporation, as Borrower, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 31, 2024).
10.21†	Chairman Emeritus Agreement, by and between Antero Resources Corporation, Antero Midstream Corporation and Paul Rady, dated August 14, 2025 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on August 14, 2025).
10.22†	Antero Resources Corporation Executive Severance Plan, effective September 17, 2025 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on September 23, 2025).
10.23†*	Form of Antero Resources Corporation Executive Severance Plan Participation Agreement.
10.24†*	Antero Resources Corporation Executive Severance Plan Participation Agreement, by and between Antero Resources Corporation and Paul Rady, dated October 2, 2025.
10.25	Antero Resources Corporation Summary of Compensation for Non-Employee Directors, effective August 14, 2025 (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 29, 2025).
10.26***	Membership Interest Purchase Agreement, by and among HG Energy II LLC, HG Energy II Production Holdings, LLC, HG Energy II Midstream Holdings, LLC, Antero Resources Corporation and Antero Midstream Partners LP, dated as of December 5, 2025 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on December 8, 2025).
10.27***	Amendment No. 1 to the Membership Interest Purchase Agreement, by and among HG Energy II LLC, HG Energy II Production Holdings, LLC, HG Energy II Midstream Holdings, LLC, Antero Resources Corporation and Antero Midstream Partners LP, dated as of December 22, 2025 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on February 3, 2026).
10.28***	Purchase and Sale Agreement, among Antero Resources Corporation, Antero Minerals LLC, Monroe Pipeline LLC, Infinity Natural Resources, LLC and Northern Oil and Gas Inc., dated December 5, 2025 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on December 8, 2025).
10.29***	Letter Agreement, by and between Antero Resources Corporation and Antero Midstream Partners LP, effective as of December 5, 2025.
10.30***	Credit Agreement, by and among Antero Resources Corporation, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent, dated February 3, 2026 (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 3, 2026).
19.1	Antero Resources Corporation Insider Trading Policies (incorporated by reference to Exhibit 19.1 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 12, 2025).
21.1*	Subsidiaries of Antero Resources Corporation.
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).
97.1	Antero Resources Corporation Incentive Compensation Recovery Policy (incorporated by reference to Exhibit 97.1 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 14, 2024).

Exhibit Number	Description of Exhibit
99.1*	Report of DeGolyer and MacNaughton, dated as of January 13, 2026, for proved reserves as of December 31, 2025.
99.2	Report of DeGolyer and MacNaughton, dated as of January 20, 2025, for proved reserves as of December 31, 2024. (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 12, 2025).
99.3	Report of DeGolyer and MacNaughton, dated as of January 17, 2024, for proved reserves as of December 31, 2023 (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 14, 2024).
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2025, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Income, (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.

*** Certain of the schedules and exhibits to this Exhibit have been omitted pursuant to Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule or exhibit will be furnished to the U.S. Securities and Exchange Commission upon request. Certain personally identifiable information has also been omitted from this Exhibit pursuant to Item 601(a)(6) of Regulation S-K.

† 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/ Brendan E. Krueger
Brendan E. Krueger
Chief Financial Officer, Senior Vice President – Finance and Treasurer

Date: February 11, 2026

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/ Michael N. Kennedy Michael N. Kennedy	Director, Chief Executive Officer and President (principal executive officer)	February 11, 2026
/s/ Brendan E. Krueger Brendan E. Krueger	Chief Financial Officer, Senior Vice President – Finance and Treasurer (principal financial officer)	February 11, 2026
/s/ Sheri L. Pearce Sheri L. Pearce	Senior Vice President – Accounting and Chief Accounting Officer (principal accounting officer)	February 11, 2026
/s/ Benjamin A. Hardesty Benjamin A. Hardesty	Chairman of the Board, Director	February 11, 2026
/s/ W. Howard Keenan, Jr W. Howard Keenan, Jr.	Director	February 11, 2026
/s/ Jeffrey S. Muñoz Jeffrey S. Muñoz	Director	February 11, 2026
/s/ Jacqueline C. Mutschler Jacqueline C. Mutschler	Director	February 11, 2026
/s/ Brenda R. Schroer Brenda R. Schroer	Director	February 11, 2026
/s/ Vicky Sutil Vicky Sutil	Director	February 11, 2026
/s/ Thomas B. Tyree, Jr. Thomas B. Tyree, Jr.	Director	February 11, 2026

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INDEX TO FINANCIAL STATEMENTS

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, 2024 and 2025, the related consolidated statements of operations and comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2025, 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, 2025, 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, 2024 and 2025, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2025, 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, 2025 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.

Assessment of the estimated oil and gas reserves 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 its proved oil and gas properties using the unit-of-production method. Under such method, capitalized costs are amortized over total estimated proved oil and gas reserves. For the year ended December 31, 2025, the Company recorded depletion expense related to proved oil and gas properties of $742 million. The estimation of proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration future production and operating costs. 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 proved oil and gas reserves, which is an input in the depletion expense calculation. Specifically, auditor judgment was required to evaluate the assumptions used by the Company related to future production and operating costs, 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 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 the external engineering firm, (2) the knowledge, skills, 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 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 read and considered the report 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 11, 2026

ANTERO RESOURCES CORPORATION

Consolidated Balance Sheets

(In thousands, except per share amounts)

		December 31, 2024	December 31, 2025
Assets			
Current assets:			
Restricted cash	$	—	210,000
Accounts receivable		34,413	33,773
Accrued revenue		453,613	473,453
Derivative instruments		1,050	68,913
Prepaid expenses		12,423	14,554
Current assets held for sale		—	20,269
Other current assets		6,047	10,818
Total current assets		507,546	831,780
Property and equipment:			
Oil and gas properties, at cost (successful efforts method):			
Unproved properties		879,483	796,705
Proved properties		14,395,680	14,049,003
Gathering systems and facilities		5,802	—
Other property and equipment		105,871	113,020
		15,386,836	14,958,728
Less accumulated depletion, depreciation and amortization		(5,699,286)	(5,753,416)
Property and equipment, net		9,687,550	9,205,312
Operating leases right-of-use assets		2,549,398	2,132,509
Derivative instruments		1,296	12,524
Investment in unconsolidated affiliate		231,048	245,653
Assets held for sale		—	754,737
Other assets		33,212	62,892
Total assets	$	13,010,050	13,245,407
Liabilities and Equity			
Current liabilities:			
Accounts payable	$	62,213	49,514
Accounts payable, related parties		111,066	101,454
Accrued liabilities		402,591	338,847
Revenue distributions payable		315,932	384,777
Derivative instruments		31,792	—
Short-term lease liabilities		493,894	516,256
Deferred revenue, VPP		25,264	23,502
Current liabilities held for sale		—	62,310
Other current liabilities		3,175	26,653
Total current liabilities		1,445,927	1,503,313
Long-term liabilities:			
Long-term debt		1,489,230	1,397,976
Deferred income tax liability, net		693,341	907,306
Derivative instruments		17,233	—
Long-term lease liabilities		2,050,337	1,612,288
Deferred revenue, VPP		35,448	11,946
Liabilities held for sale		—	39,789
Other liabilities		62,001	57,140
Total liabilities		5,793,517	5,529,758
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; 311,165 and 308,510 shares issued and outstanding as of December 31, 2024 and December 31, 2025, respectively		3,111	3,085
Additional paid-in capital		5,909,373	5,865,447
Retained earnings		1,109,166	1,682,295
Total stockholders' equity		7,021,650	7,550,827
Noncontrolling interests		194,883	164,822
Total equity		7,216,533	7,715,649
Total liabilities and equity	$	13,010,050	13,245,407

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income

(In thousands, except per share amounts)

	Year Ended December 31,		
	2023	2024	2025
Revenue and other:			
Natural gas sales	$ 2,192,349	1,818,297	2,873,241
Natural gas liquids sales	1,836,950	2,066,975	1,986,840
Oil sales	247,146	230,027	150,158
Commodity derivative fair value gains	166,324	731	111,049
Marketing	206,122	179,069	125,900
Amortization of deferred revenue, VPP	30,552	27,101	25,264
Other revenue and income	2,529	3,396	3,371
Total revenue	4,681,972	4,325,596	5,275,823
Operating expenses:			
Lease operating	118,441	118,693	135,124
Gathering, compression, processing and transportation	2,642,358	2,702,930	2,857,426
Production and ad valorem taxes	158,855	207,671	163,135
Marketing	284,965	244,906	190,206
Exploration	2,700	2,618	2,990
General and administrative (including equity-based compensation expense of $59,519, $66,462 and $60,812 in 2023, 2024 and 2025, respectively)	224,516	229,338	232,526
Depletion, depreciation and amortization	746,849	762,068	749,675
Impairment of property and equipment	51,302	47,433	29,358
Accretion of asset retirement obligations	3,244	3,759	3,892
Contract termination, loss contingency and settlements	52,606	4,468	28,012
Loss (gain) on sale of assets	(447)	862	(266)
Other operating expense	336	390	99
Total operating expenses	4,285,725	4,325,136	4,392,177
Operating income	396,247	460	883,646
Other income (expense):			
Interest expense, net	(117,870)	(118,207)	(83,682)
Equity in earnings of unconsolidated affiliate	82,952	93,787	98,484
Loss on early extinguishment of debt	—	(528)	(3,628)
Loss on convertible note inducements	(374)	—	—
Transaction expense	—	—	(4,386)
Total other income (expense)	(35,292)	(24,948)	6,788
Income (loss) before income taxes	360,955	(24,488)	890,434
Income tax (expense) benefit	(63,626)	118,185	(215,867)
Net income and comprehensive income including noncontrolling interests	297,329	93,697	674,567
Less: net income and comprehensive income attributable to noncontrolling interests	98,925	36,471	40,149
Net income and comprehensive income attributable to Antero Resources Corporation	$ 198,404	57,226	634,418
Income per share—basic	$ 0.66	0.18	2.05
Income per share—diluted	$ 0.64	0.18	2.03
Weighted average number of common shares outstanding:			
Basic	299,793	309,489	309,719
Diluted	311,597	313,414	312,361

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, 2022	297,393	$ 2,974	5,838,848	878,523	(34)	$ (1,160)	262,596	6,981,781
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	—	—	—	198,404	—	—	98,925	297,329
Balances, December 31, 2023	303,544	3,035	5,846,541	1,051,940	—	—	232,698	7,134,214
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,547	15	(29,620)	—	—	—	—	(29,605)
Conversion of 2026 Convertible Notes	6,074	61	25,990	—	—	—	—	26,051
Equity-based compensation	—	—	66,462	—	—	—	—	66,462
Distributions to noncontrolling interests	—	—	—	—	—	—	(74,286)	(74,286)
Net income and comprehensive income	—	—	—	57,226	—	—	36,471	93,697
Balances, December 31, 2024	311,165	3,111	5,909,373	1,109,166	—	—	194,883	7,216,533
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,302	13	(29,662)	—	—	—	—	(29,649)
Repurchases and retirements of common stock	(3,957)	(39)	(75,076)	(61,289)	—	—	—	(136,404)
Equity-based compensation	—	—	60,812	—	—	—	—	60,812
Distributions to noncontrolling interests	—	—	—	—	—	—	(70,210)	(70,210)
Net income and comprehensive income	—	—	—	634,418	—	—	40,149	674,567
Balances, December 31, 2025	308,510	$ 3,085	5,865,447	1,682,295	—	$ —	164,822	7,715,649

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2023	2024	2025
Cash flows provided by (used in) operating activities:			
Net income including noncontrolling interests	$ 297,329	93,697	674,567
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, amortization and accretion	750,093	765,827	753,567
Impairment of property and equipment	51,302	47,433	29,358
Commodity derivative fair value gains	(166,324)	(731)	(111,049)
Settled commodity derivative gains (losses)	(25,383)	10,154	(17,068)
Payments for derivative monetizations	(202,339)	—	—
Deferred income tax expense (benefit)	62,039	(118,640)	213,965
Equity-based compensation expense	59,519	66,462	60,812
Equity in earnings of unconsolidated affiliate	(82,952)	(93,787)	(98,484)
Dividends of earnings from unconsolidated affiliate	125,138	125,197	125,255
Amortization of deferred revenue	(30,552)	(27,101)	(25,264)
Amortization of debt issuance costs and other	2,264	2,420	937
Settlement of asset retirement obligations	(718)	(3,571)	(270)
Contract termination, loss contingency and settlements	12,100	5,344	15,370
Loss (gain) on sale of assets	(447)	862	(266)
Loss on early extinguishment of debt	—	528	3,628
Loss on convertible note inducements	374	—	—
Changes in current assets and liabilities:			
Accounts receivable	7,550	25,410	(142)
Accrued revenue	306,880	(52,808)	(39,239)
Prepaid expenses and other current assets	14,890	8,680	(6,990)
Accounts payable including related parties	(16,837)	35,301	(2,345)
Accrued liabilities	(62,419)	1,280	(44,984)
Revenue distributions payable	(106,429)	(45,849)	85,975
Other current liabilities	(357)	3,180	13,597
Net cash provided by operating activities	994,721	849,288	1,630,930
Cash flows provided by (used in) investing activities:			
Additions to unproved properties	(151,135)	(90,995)	(129,247)
Drilling and completion costs	(964,346)	(614,855)	(685,468)
Additions to other property and equipment	(16,382)	(10,929)	(5,407)
Acquisitions of oil and gas properties	—	—	(253,128)
Proceeds from asset sales	447	9,499	16,277
Change in other assets	(9,351)	(6,873)	(20,840)
Net cash used in investing activities	(1,140,767)	(714,153)	(1,077,813)
Cash flows provided by (used in) financing activities:			
Repurchases of common stock	(75,355)	—	(136,404)
Repayment of senior notes	—	—	(141,733)
Borrowings on Credit Facility	4,501,400	4,130,900	4,909,000
Repayments on Credit Facility	(4,119,000)	(4,154,900)	(4,863,600)
Payment of debt issuance costs	(605)	(6,138)	(8,983)
Distributions to noncontrolling interests	(128,823)	(74,286)	(70,210)
Employee tax withholding for settlement of equity-based compensation awards	(30,367)	(29,605)	(29,649)
Convertible note inducements	(374)	—	—
Other	(830)	(1,106)	(1,538)
Net cash provided by (used in) financing activities	146,046	(135,135)	(343,117)
Net increase in cash, cash equivalents and restricted cash	—	—	210,000
Cash, cash equivalents and restricted cash, beginning of period	—	—	—
Cash, cash equivalents and restricted cash, end of period	$ —	—	210,000
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 113,910	120,058	88,079
Increase (decrease) in accounts payable and accrued liabilities for additions to property and equipment	$ (60,762)	10,525	(27,325)
Increase in other current liabilities for acquisitions of oil and gas properties	$ —	—	7,479

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, 2024 and 2025, and its results of operations and cash flows for the years ended December 31, 2023, 2024 and 2025. 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, 2023, 2024 and 2025, 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 using the equity method of accounting. As of December 31, 2024 and 2025, the Company had a 29% 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 the Company's ownership interest, representation on the board of directors, participation in the policy-making decisions of the investee and material intercompany transactions. Such investments are included in investment in unconsolidated affiliate on the Company's consolidated balance sheets. Income (loss) from an investee that is 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 and cash flows. When the Company records its proportionate share of net income (loss), it is recorded in equity in earnings (loss) of unconsolidated affiliate in the statements of operations and comprehensive income and the carrying value of that investment on the Company's balance sheet. Distributions received from an equity method investee are recorded as reductions to the carrying value of that investment on the Company's balance sheet. The Company's equity in earnings (loss) of unconsolidated affiliate 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") from the Company deconsolidation of Antero Midstream Partners as of March 12, 2019. Basis difference are amortized into equity in earnings (loss) of unconsolidated affiliate on the Company's consolidated statements of operations and comprehensive income over the remaining useful lives of the underlying assets and liabilities. See Note 5—Equity Method Investments for additional information.

Distributions received from equity method investees are recorded as reductions to the carrying value of the investment on the consolidated balance sheet. 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 provided by operating activities) or a return of investment (classified as cash provided by 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, 2024, the book overdrafts included within accounts payable and revenue distributions payable were $14 million and $17 million, respectively. As of December 31, 2025, the book overdrafts included within accounts payable and revenue distributions payable were each $18 million.

(f) Restricted Cash

The Company classifies restricted cash as all cash that is legally or contractually restricted to withdrawal or usage, including amounts deposited in escrow that are restricted from use. The Company's restricted cash is classified as a current asset as of December 31, 2025 because the restriction on such cash was released on February 3, 2026 at the closing of the HG Acquisition.

(g) 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 $51 million, $47 million and $29 million for the years ended December 31, 2023, 2024 and 2025, 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, 2023, 2024 and 2025.

As of December 31, 2025, 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 $739 million, $754 million and $742 million for the years ended December 31, 2023, 2024 and 2025, respectively.

(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 $8 million for each of the years ended December 31, 2023, 2024 and 2025. A gain or loss is recognized upon the sale or disposal of other property and equipment.

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. There were no such impairments for the years ended December 31, 2023, 2024 and 2025.

(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, 2024, the Company had $9 million of unamortized debt issuance costs included in other long-term assets, and $8 million of unamortized debt issuance costs included as a reduction to long-term debt. As of December 31, 2025, the Company had $16 million of unamortized debt issuance costs included in other long-term assets, and $6 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 $4 million, $4 million and $3 million for the years ended December 31, 2023, 2024 and 2025, 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. 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, 2024 and 2025, 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.

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.

(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.

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.

(p) Concentrations of Credit Risk

The Company's revenues from its exploration and production and marketing reportable segments are derived principally from uncollateralized sales to purchasers in the oil and gas industry or the utilities industry. The Company also contracts with the primary processor of its natural gas, MarkWest, to market a portion of the Company's NGLs, which accounted for approximately 16% of the Company's sales for the years ended December 31, 2023 and 2024. The concentration of credit risk 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. No customer accounted for more than 10% of the Company's sales for the years ended December 31, 2023, 2024 and 2025, except MarkWest as disclosed.

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 eight different counterparties and had derivative assets of $81 million with bank counterparties under the Unsecured Credit Facility as of December 31, 2025. 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, 2025 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. The effect of tax credits related to historical periods is recognized during the period when such credit is claimed on a filed tax return. 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.

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

On July 4, 2025, Public Law No. 119-21, commonly referred to as the One Big Beautiful Bill Act (the “OBBB”), was enacted. The OBBB contains a broad range of changes to U.S. federal income tax laws and makes permanent or modifies certain provisions of Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act. These changes include, among others, permanently restoring an earnings before interest, taxes, depreciation and amortization expense based business interest deduction limitation, 100% bonus depreciation for certain property and immediate expensing for certain domestic research and experimental expenditures. All effects of changes in tax laws are recognized in the consolidated financial statements during the period of enactment. As such, the effects of the OBBB are reflected in the Company's provision for income taxes as of and for the year ended December 31, 2025. The OBBB did not have a material effect on income tax expense for the year ending December 31, 2025.

(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, and production, (ii) marketing and (iii) equity method investment in Antero Midstream. See Note 17—Reportable Segments for additional 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.

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

(t) Net Income Per Common Share

Net income per common share—basic for each period is computed by dividing net income attributable to Antero by the basic weighted average number of common shares outstanding during the period. Net income per common share—diluted for each period is computed after giving consideration to the potential dilution from (i) outstanding equity-based 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, PSU awards and stock options in the calculation of diluted weighted average common 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 common shares outstanding is equal to basic weighted average common shares outstanding because the effects of all equity-based awards and the 2026 Convertible Notes are anti-dilutive.

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

	Year Ended December 31,		
	2023	**2024**	**2025**
Net income attributable to Antero Resources Corporation—common shareholders	$ 198,404	57,226	634,418
Add: Interest expense for 2026 Convertible Notes	1,955	256	—
Less: Tax-effect of interest expense for 2026 Convertible Notes	(425)	(56)	—
Net income attributable to Antero Resources Corporation—common shareholders and assumed conversions	$ 199,934	57,426	634,418
Net income per common share—basic	$ 0.66	0.18	2.05
Net income per common share—diluted	$ 0.64	0.18	2.03
Weighted average common shares outstanding—basic	299,793	309,489	309,719
Weighted average common shares outstanding—diluted	311,597	313,414	312,361

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

	Year Ended December 31,		
	2023	**2024**	**2025**
Basic weighted average number of common shares outstanding	299,793	309,489	309,719
Add: Dilutive effect of RSUs	1,379	1,188	1,128
Add: Dilutive effect of PSUs	989	1,528	1,514
Add: Dilutive effect of 2026 Convertible Notes	9,436	1,209	—
Diluted weighted average number of common shares outstanding	311,597	313,414	312,361
Weighted average number of outstanding securities excluded from calculation of diluted net income per common share (1):			
RSUs	1,200	4	—
PSUs	199	—	—
Stock options	310	257	73

(1) The potential dilutive effects of these securities were excluded from the computation of net income per common share—diluted because the inclusion of these securities 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's equity-based compensation expense is included in general and administrative expenses, and recorded as a credit to additional paid-in capital. 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 for additional information.

(w) Recently Adopted or Issued Accounting Standards

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. The Company adopted ASU 2023-07 in the 2024 Form 10-K for the year ended December 31, 2024, and it did not have a material impact on the Company's consolidated financial statements.

Income Taxes

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 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. ASU 2023-09 should be applied on a prospective basis, although retrospective application is permitted. The Company adopted ASU 2023-09 retrospectively in this Annual Report on Form 10-K for the year ended December 31, 2025, and it did not have a material impact on the Company's consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU No. 2024-03, Disaggregation of Income Statement Expenses ("ASU 2024-03"). ASU 2024-03 is intended to improve the disclosure about certain operating expenses primarily through enhanced disclosure of cost of sales and selling, general and administrative expenses. This ASU is effective for annual reporting periods beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted. ASU 2024-03 can be applied on either a prospective or a retrospective basis at the Company's election. The Company is evaluating the impact that ASU 2024-03 will have on the consolidated financial statements and its plans for adoption, including its transition method and 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 has 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) could be re-conveyed to the Company (at the Company's election) if certain production targets attributable to the ORRIs were achieved through March 31, 2023. Any portion of the Incremental Override that could 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. The Company expects the Hurdle be achieved during the first half of 2026.

(b) 2021-2024 Drilling Partnership

On February 17, 2021, the Company 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 participated represented an annual tranche, and QL was conveyed a working interest in any wells spud by the Company during such tranche year. For 2021 through 2024, the Company 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. The Company developed and managed the drilling program associated with each tranche, including the selection of wells. Additionally, for each annual tranche, the Company and QL entered into assignments, bills of sale and conveyances pursuant to which QL was conveyed a proportionate working interest percentage in each well spud in that year, which conveyances are not subject to any reversion. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche were for the Company's 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.

Under the terms of the arrangement, QL funded development capital of 20% for wells spud in 2021 and 2024, 15% for wells spud in 2022 and 2023, which funding amounts represented QL's proportionate working interest in such wells. Additionally, the Company may receive a carry in the form of a one-time payment from QL for each annual tranche if the IRR for such tranche exceeded 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 total carry of $117 million for the 2021-2024 Drilling Partnership, including $29 million, $32 million and $27 million during the years ended December 31, 2023, 2024 and 2025, respectively.

The Company has accounted for the 2021-2024 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 any of the interests conveyed to QL during the term of the 2021-2024 Drilling Partnership.

(c) 2025 Drilling Partnership

On December 11, 2024, the Company entered into a drilling partnership with an unaffiliated third-party. Under the terms of the arrangement, the third-party will participate in and fund a share of total development capital expenses for wells spud by the Company during the 2025 calendar year. For each well spud during the 2025 calendar year, the third-party will receive a 15% working interest in such wells and will fund greater than 15% of total development capital expenses for such wells. Subject to the preceding sentence, for any wells spud in the calendar year 2025, the third-party 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. Additionally, for each well in the partnership, the Company will enter into an assignment, bill of sale and conveyance pursuant to which the third-party will be conveyed a proportionate working interest percentage in such well, which conveyances will not be subject to any reversion.

The Company has accounted for the 2025 Drilling Partnership as a conveyance under ASC 932 and such conveyances are recorded in the consolidated financial statements as the third-party obtains its proportionate working interest in each well. No gain or loss was recognized for any of the interests conveyed during the year ended December 31, 2025.

(d) Acquisitions

Asset Acquisitions

During the year ended December 31, 2025, the Company acquired additional working and royalty interests in certain Antero-operated producing wells for a total of approximately $260 million, before closing adjustments. The Company accounted for these transactions as asset acquisitions and as such, substantially all of the cash consideration was allocated to proved properties in the consolidated balance sheets.

HG Acquisition

On December 5, 2025, the Company entered into a definitive agreement to acquire 100% of the issued and outstanding equity interests of HG Production for total cash consideration of $2.8 billion, subject to the term and conditions thereof. The HG Acquisition includes approximately 385,000 net acres in the core of the Marcellus Shale in West Virginia. Pursuant to the same agreement, Antero Midstream Partners agreed to acquire 100% of the issued and outstanding equity interests of HG Midstream for cash consideration of $1.1 billion, subject to the terms and conditions thereof. The HG Midstream Acquisition includes gathering pipelines and integrated water handling assets in the core of the Marcellus Shale in West Virginia. In connection with the Company's entry into the definitive purchase agreement, the Company and Antero Midstream agreed to allocate between the parties certain benefits and costs under the agreement and the buyer-side representations and warranties insurance policies. On December 8, 2025, the Company deposited $210 million into escrow to be credited towards the cash consideration payable at the closing of the HG Acquisition, which is classified as restricted cash on the Company's consolidated balance sheets as of December 31, 2025. These acquisitions closed on February 3, 2026, with effective dates of January 1, 2026. The Company intends to make certain modifications to its existing commercial arrangements with Antero Midstream to provide for on-pad compression with respect to certain wells and to provide a transition period through 2026 before certain water services would be provided under the Company's existing agreements with Antero Midstream.

The disclosure of certain financial information required by FASB ASC Topic 805, *Business Combinations*, has been omitted as it is impracticable to provide such information due to the timing of the closing of the HG Acquisition and issuance of the Company's consolidated financial statements.

(e) Utica Shale Divestiture

On December 5, 2025, the Company entered into a purchase and sale agreement with the Buyer Parties to sell the Company's Utica Shale Properties, for aggregate cash consideration of $800 million, subject to the terms and conditions thereof. The Utica Shale Properties include approximately 80,000 gross (70,000 net) acres located in Ohio and proved reserves of approximately 600 Bcfe as of December 31, 2025. The Utica Shale Divestiture is expected to close in February 2026, with an effective date of July 1, 2025, subject to the satisfaction of certain customary closing conditions.

The Utica Shale Properties and its associated assets and liabilities have been classified as held for sale as of December 31, 2025 on the Company's consolidated balance sheets, which relate to the Company's exploration and production reportable segment. The Utica Shale Divestiture does not qualify as a discontinued operation under FASB ASC Topic 205, *Presentation of Financial Statements*, as it does not represent a strategic shift that will have a major effect on the Company's operations or financial results.

The following table sets forth the carrying value of the Utica Shale Properties assets and liabilities held for sale (in thousands):

		December 31, 2025
Current assets:		
Accounts receivable	$	782
Accrued revenue		19,399
Other current assets		88
Long-term assets:		
Unproved properties		27,720
Proved properties		1,045,145
Gathering systems and facilities		5,802
Other property and equipment		581
Less accumulated depletion, depreciation and amortization		(369,995)
Property and equipment, net		709,253
Operating leases right-of-use assets [1]		44,825
Other assets		659
Total	$	775,006
Current liabilities:		
Accounts payable	$	2,118
Accounts payable, related parties		4,600
Accrued liabilities		17,650
Revenue distributions payable		17,130
Short-term lease liabilities		20,812
Long-term liabilities:		
Long-term lease liabilities		24,210
Other liabilities		15,579
Total	$	102,099

(1) Substantially all of these operating leases right-of-use-assets relate to a gas gathering line and compressors station with Antero Midstream. See Note 12— Leases for additional information.

(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 for additional information on reportable segments.

	Year Ended December 31,			
	2023	**2024**	**2025**	**Reportable Segment**
Revenues from contracts with customers:				
Natural gas sales	$ 2,192,349	1,818,297	2,873,241	Exploration and production
Natural gas liquids sales (ethane)	250,116	275,120	355,437	Exploration and production
Natural gas liquids sales (C3+ NGLs)	1,586,834	1,791,855	1,631,403	Exploration and production
Oil sales	247,146	230,027	150,158	Exploration and production
Marketing	206,122	179,069	125,900	Marketing
Other revenue	633	1,098	1,095	Exploration and production
Total revenue from contracts with customers	4,483,200	4,295,466	5,137,234	
Income from derivatives, deferred revenue and other sources, net	198,772	30,130	138,589	
Total revenue	$ 4,681,972	4,325,596	5,275,823	

(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 FASB ASC Topic 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, 2024 and 2025, the Company's receivables from contracts with customers were $454 million and $493 million, respectively.

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

(5) Equity Method Investment

(a) Summary of Equity Method Investment

As of December 31, 2024 and 2025, Antero owned 29% 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, 2023	$	222,255
Additional investments [1]		1,936
Equity in earnings of unconsolidated affiliate		93,787
Dividends from unconsolidated affiliate		(125,197)
Elimination of intercompany profit		38,267
Balance as of December 31, 2024 [2]		231,048
Equity in earnings of unconsolidated affiliate		98,484
Dividends from unconsolidated affiliate		(125,255)
Elimination of intercompany profit		41,376
Balance as of December 31, 2025 [2]	$	245,653

(1) During the year ended December 31, 2024, the Company received 0.1 million additional shares of Antero Midstream common stock as part of a judgment in a legal proceeding with an unaffiliated third-party.
(2) The fair value of the Company's investment in Antero Midstream as of December 31, 2024 and 2025 was $2.1 billion and $2.5 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,		
		2024	2025
Current assets	$	118,064	379,864
Noncurrent assets		5,643,684	5,504,252
Total assets	$	5,761,748	5,884,116
Current liabilities	$	100,612	111,482
Noncurrent liabilities		3,545,965	3,800,593
Stockholders' equity		2,115,171	1,972,041
Total liabilities and stockholders' equity	$	5,761,748	5,884,116

Statement of Operations

	Year Ended December 31,			
		2023	2024	2025
Revenues	$	1,041,771	1,106,193	1,188,426
Operating expenses		429,909	447,027	543,757
Income from operations		611,862	659,166	644,669
Net income	$	371,786	400,892	413,163

(6) Accrued Liabilities

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

	December 31,	
	2024	2025
Capital expenditures	$ 42,474	32,656
Gathering, compression, processing and transportation expenses	167,915	169,270
Marketing expenses	16,891	12,851
Interest expense, net	29,014	24,256
Production and ad valorem taxes	78,980	22,770
General and administrative expense	37,516	40,663
Contingencies and other	29,801	36,381
Total accrued liabilities	$ 402,591	338,847

(7) Long-Term Debt

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

	December 31,	
	2024	2025
Credit Facility	$ 393,200	438,600
8.375% senior notes due 2026	96,870	—
7.625% senior notes due 2029	407,115	365,353
5.375% senior notes due 2030	600,000	600,000
Total principal	1,497,185	1,403,953
Unamortized debt issuance costs	(7,955)	(5,977)
Long-term debt	$ 1,489,230	1,397,976

(a) Credit Facility

Antero Resources has a senior revolving credit facility with a syndicate of bank lenders. References to the (i) “Secured Credit Facility” (defined below) refer to the credit facility in effect for periods prior to July 30, 2024, (ii) “Unsecured Credit Facility” (defined below) refer to the credit facility in effect on or after July 30, 2024 and (iii) “Credit Facility” refer to the Secured Credit Facility and Unsecured Credit Facility, collectively.

Senior Unsecured Revolving Credit Facility

On July 30, 2024, Antero Resources entered into an amendment and restatement of its senior revolving credit facility with a syndicate of bank lenders (“Unsecured Credit Facility”). Borrowings are unsecured and are not guaranteed by any of Antero Resources’ subsidiaries. As of December 31, 2025, the Unsecured Credit Facility had lender commitments of $1.65 billion and available borrowing capacity of $1.2 billion. The Unsecured Credit Facility was originally scheduled to mature on July 30, 2029 (the “Maturity Date”); however, Antero Resources may request two one-year extensions of the Maturity Date, subject to satisfaction of certain conditions and consent of the extending lenders. Effective July 30, 2025, Antero Resources obtained the consent of each of the lenders party to the Unsecured Credit Facility to extend the Maturity Date to July 30, 2030. Commitments under the Unsecured Credit Facility may be increased by up to $500 million subject to the agreement of Antero Resources, the increasing lenders, and with respect to the addition of new lenders, the consent of the Administrative Agent under the Unsecured Credit Facility and the lenders with commitments to issue letters of credit under the Unsecured Credit Facility.

The Unsecured Credit Facility contains one financial covenant requiring Antero Resources to maintain a ratio on a consolidated basis of total indebtedness to capitalization of 65% or less at the end of each fiscal quarter and other affirmative and negative covenants applicable to Antero Resources and its subsidiaries that are customary for credit facilities of this type, including, among other things, limitations on: fundamental changes such as mergers, consolidations, liquidations and dissolutions; liens; certain indebtedness; restricted payments such as dividends, distributions and equity repurchases; and material non-arms'-length transactions with its affiliates. Antero Resources was in compliance with the financial covenant under the Unsecured Credit Facility as of December 31, 2025.

The Unsecured Credit Facility provides for borrowing at SOFR or an Alternate Base Rate, in each case, plus an Applicable Rate (each as defined in the Unsecured Credit Facility). There is a 0.10% credit adjustment spread on SOFR and a 0.00% floor. The Unsecured Credit Facility does not amortize. Interest under the Unsecured Credit Facility is payable at a variable rate based on SOFR or the Alternate Base Rate, determined by election at the time of borrowing and at the end of each applicable interest period in respect of a borrowing, plus an Applicable Rate. The Applicable Rate is determined with reference to Antero Resources' then-current senior unsecured long-term debt rating ranging from 1.125% to 2.00% for SOFR loans. Commitment fees on the unused portion of the Unsecured Credit Facility are due quarterly at rates ranging from 0.125% to 0.300%, determined with reference to Antero Resources' then-current senior unsecured long-term debt ratings.

The proceeds of the loans made under the Unsecured Credit Facility may be used (i) to pay fees and expenses incurred in connection with the transactions related thereto and the refinancing of the Secured Credit Facility (defined below), (ii) to finance working capital needs and (iii) for other general corporate purposes, in each case of Antero Resources and its subsidiaries.

As of December 31, 2024, Antero Resources had an outstanding balance under the Unsecured Credit Facility of $393 million, with a weighted average interest rate of 5.9%, and outstanding letters of credit of $13 million. As of December 31, 2025, Antero Resources had an outstanding balance under the Unsecured Credit Facility of $439 million, with a weighted average interest rate of 5.3%, and outstanding letters of credit of $12 million.

Senior Secured Revolving Credit Facility

On October 26, 2021, Antero Resources entered into an amended and restated senior secured revolving credit facility with a syndicate of bank lenders ("Secured Credit Facility"). Borrowings were secured by substantially all of the assets of Antero Resources and certain of its subsidiaries, were subject to borrowing base limitations based on the collateral value of Antero Resources' assets and were subject to regular semi-annual redeterminations. The Secured Credit Facility was refinanced in full and terminated upon the closing of the Unsecured Credit Facility on July 30, 2024.

The Secured Credit Facility provided for borrowing at either an Adjusted Term SOFR, an Adjusted Daily Simple SOFR or an Alternate Base Rate, in each case, plus an Applicable Margin (each as defined in the Secured Credit Facility). The Secured Credit Facility provided for interest only payments until maturity at which time all outstanding borrowings would be due. Interest was 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 under the Secured Credit Facility. The Applicable Margin was determined with reference to Antero Resources' then-current leverage ratio subject to certain exceptions, which for SOFR loans ranged from 1.75% to 2.75% during a non-investment grade period (based on utilization of the Secured Credit Facility) and 1.25% and 1.875% during an investment grade period (based on a ratings grid). Commitment fees on the unused portion of the Secured Credit Facility were due quarterly at rates ranging from 0.375% to 0.500% with respect to the Secured Credit Facility, determined with reference to borrowing base utilization, subject to certain exceptions based on the leverage ratio then in effect. The Secured Credit Facility included fall away covenants, lower interest rates and reduced collateral requirements that Antero Resources could elect if Antero Resources was assigned an Investment Grade Rating (as defined in the Secured Credit Facility).

(b) 8.375% Senior Notes Due 2026

On January 4, 2021, Antero Resources issued $500 million of 8.375% senior notes due July 15, 2026 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. On March 5, 2025, the Company redeemed the remaining $97 million principal amount of the 2026 Notes at 102.094% of the principal amount thereof, plus accrued and unpaid interest, and the 2026 Notes were fully retired on such date. Interest on the 2026 Notes was payable on January 15 and July 15 of each year.

(c) 7.625% Senior Notes Due 2029

On January 26, 2021, Antero Resources issued $700 million of 7.625% senior notes due February 1, 2029 at par. The Company redeemed or otherwise repurchased $293 million principal amount of the 2029 Notes during 2021 and 2022. During the year ended December 31, 2025, the Company repurchased $42 million principal amount of the 2029 Notes through open market transactions at a weighted average price of approximately 103% of the principal amount thereof, plus accrued and unpaid interest. As of December 31, 2025, $365 million principal amount of the 2029 Notes remained outstanding. The 2029 Notes are unsecured and rank pari passu to Antero Resources' Unsecured Credit Facility and other outstanding senior notes. As of July 30, 2024, the 2029 Notes are not guaranteed by any of Antero Resources' 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 at redemption prices ranging from 102.542% as of December 31, 2025 to 100.00% on or after February 1, 2027. 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.

(d) 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 rank pari passu to Antero Resources' Unsecured Credit Facility and other outstanding senior notes. As of July 30, 2024, the 2030 Notes are not guaranteed by any of Antero Resources' 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 at redemption prices ranging from 102.688% as of December 31, 2025 to 100.00% on or after March 1, 2028. 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.

(e) 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. Transaction costs related to the 2026 Convertible Notes 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.

The Company extinguished $206 million principal amount of the 2026 Convertible Notes in 2021. In addition, between 2022 and 2024, $81 million aggregate principal amount of the 2026 Convertible Notes were converted pursuant to their terms or induced into conversion by the Company, and as of March 14, 2024, no 2026 Convertible Notes remained outstanding. See "—Conversions and Inducements," for more information.

The 2026 Convertible Notes bore 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. The initial conversion rate was 230.2026 shares of Antero Resources' common stock per $1,000 principal amount of 2026 Convertible Notes, and such conversion rate was not adjusted during the term for which the 2026 Convertible Notes were outstanding. The noteholders had the right to convert their 2026 Convertible Notes only upon the occurrence of certain events pursuant to the terms and conditions provided in the indenture governing the 2026 Convertible Notes. Upon conversion, Antero Resources could 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.

Conversions and Inducements

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.

On March 11, 2024, the Company called the $26 million aggregate principal amount of the 2026 Convertible Notes that remained outstanding for redemption on April 1, 2024, at a redemption price equal to 100% of the principal amount thereof, plus accrued and unpaid interest. The Company's election to call the remaining 2026 Convertible Notes allowed holders of the 2026 Convertible Notes to exercise their conversion right through March 28, 2024. During the first quarter of 2024, all remaining $26 million aggregate principal amount of the 2026 Convertible Notes converted pursuant to their terms. The Company elected to settle these conversions by issuing 6 million shares of common stock to the noteholders.

(f) Term Loans

In connection with the signing of the HG Acquisition, the Company entered into a debt commitment letter dated December 5, 2025 with Royal Bank of Canada, RBC Capital Markets and JPMorgan Chase Bank, N.A. (collectively, the "Banks"), pursuant to which the Banks committed, subject to satisfaction of certain customary terms and conditions, to provide the Company with an unsecured 364-day term loan facility in an aggregate principal amount of $800 million (the "Term Loan Bridge Facility") and an unsecured 3-year term loan facility in an aggregate principal amount of $1.5 billion (the "Term Loan A Facility"). As of December 31, 2025, the Company had not entered into definitive agreements with respect to either of the Term Loan Bridge Facility or the Term Loan A Facility. In connection with the issuance of the 2036 Notes, Antero Resources and the Banks terminated the commitments with respect to the Term Loan Bridge Facility.

(g) Subsequent Events

Issuance of 2036 Notes

On January 28, 2026, Antero Resources issued $750 million of 5.400% senior notes due February 1, 2036 (the "2036 Notes") at a price of 99.869% of par. Interest on the 2036 Notes is payable on February 1 and August 1 of each year, commencing August 1, 2026. The 2036 Notes are unsecured and rank pari passu to Antero Resources' Unsecured Credit Facility, Term Loan A Facility and other outstanding senior notes. The 2036 Notes are not guaranteed by any of Antero Resources' subsidiaries. Prior to November 1, 2035 (the "Par Call Date"), Antero Resources may redeem all or part of the 2036 Notes at any time at a redemption price equal to the greater of (i) (a) the sum of the present values of the remaining scheduled payments of principal and interest thereon discounted to the redemption date (assuming the 2036 Notes mature on the Par Call Date) on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined in the indenture governing the 2036 Notes) plus 20 basis points less (b) interest accrued to the date of redemption, and (ii) 100% of the principal amount of the 2036 Notes to be redeemed, plus, in either case, accrued and unpaid interest thereon to the redemption date. On or after the Par Call Date, Antero Resources may redeem the 2036 Notes, in whole or in part, at any time and from time to time, at a redemption price equal to 100% of the principal amount of the 2036 Notes being redeemed plus accrued and unpaid interest thereon to the redemption date.

Term Loan A

On February 3, 2026, substantially concurrently with the consummation of the HG Acquisition, Antero Resources entered into the Term Loan A Facility with the Banks. Borrowings are unsecured and are not guaranteed by any of Antero Resources' subsidiaries. The proceeds of the loans made under the Term Loan A Facility were used to (i) finance a portion of the consideration for the HG Acquisition and (ii) to pay fees and expenses incurred in connection with the transactions related thereto. On February 3, 2026, Antero Resources borrowed $1.5 billion in a single borrowing to partially fund the HG Acquisition. The Term Loan A Facility is scheduled to mature on February 3, 2029.

The Term Loan A Facility contains the same financial covenant as our Unsecured Credit Facility requiring Antero Resources to maintain a ratio on a consolidated basis of total indebtedness to capitalization of 65% or less at the end of each fiscal quarter and other affirmative and negative covenants applicable to Antero Resources that are customary for credit facilities of this type, including, among other things, limitations on: fundamental changes such as mergers, consolidations, liquidations and dissolutions; liens; certain indebtedness; restricted payments such as dividends, distributions and equity repurchases; and material non-arms'-length transactions with its affiliates.

The Term Loan A Facility provides for borrowings at Term SOFR or an Alternate Base Rate at our option, in each case, plus an Applicable Rate (each, as defined in the Term Loan A Facility). There is a 0.10% credit adjustment spread on SOFR and a 0.00% floor. The Term Loan A Facility does not amortize. Interest under the Term Loan A Facility is payable at a variable rate based on SOFR or the Alternate Base Rate, determined by election at the time of borrowing and at the end of each applicable interest period in respect of a borrowing, plus an Applicable Rate. The Applicable Rate is determined with reference to Antero Resources' then-current senior unsecured long-term debt rating, ranging from 1.125% to 2.00% for Term SOFR loans.

Notice of Redemption of 2029 Notes

On February 9, 2026, the Company notified the holders of the 2029 Notes of the Company's intent to redeem all $365 million aggregate principal amount of the 2029 Notes on February 24, 2026, subject to certain conditions, including the closing of the Utica Shale Divestiture, at a redemption price of 101.271%, plus accrued and unpaid interest.

(8) Asset Retirement Obligations

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

	Year Ended December 31,	
	2024	2025
Beginning balance	$ 59,214	62,001
Obligations incurred	991	697
Accretion expense	3,759	3,892
Settlement of obligations	(3,571)	(270)
Obligations on sold properties	(1,587)	—
Revisions to prior estimates	3,195	6,398
Liabilities classified as held for sale	—	(15,579)
Ending balance	$ 62,001	57,139

Revisions to prior estimates during the year ended December 31, 2024 was primarily due to decreased estimated well lives. Revisions to prior estimates during the year ended December 31, 2025 was primarily related to increased future plugging and abandonment cost estimates, partially offset by increased 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 "AR LTIP"), which replaced the Antero Resources Corporation Long Term Incentive Plan (the "2013 Plan") and became effective as of such date. On June 5, 2024, the Company's stockholders approved the Amended AR LTIP. This amendment increased the number of shares of the Company's common stock reserved for awards from 10,050,000 shares to 14,916,100 shares, and extended the term of the plan from June 17, 2030 to June 5, 2034. The Amended AR LTIP 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 (the "Board"). Employees, officers, non-employee directors and other service providers of the Company and its affiliates are eligible to receive awards under the Amended AR LTIP.

The Amended AR LTIP provides for the reservation of 14,916,100 shares of the Company's common stock, plus the number of certain shares that become available again for delivery 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 the actual delivery of shares to be considered not delivered and thus, available for new awards under the Amended AR LTIP. 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 AR LTIP or Amended AR LTIP (other than stock options and stock appreciation rights), will again be available for new awards under the Amended AR LTIP.

A total of 10,415,568 shares were available for future grant under the Amended AR LTIP as of December 31, 2025.

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

	Year Ended December 31,		
	2023	2024	2025
RSU awards	$ 32,745	42,780	41,664
PSU awards	25,322	22,177	17,543
Equity awards issued to directors	1,452	1,505	1,605
Total expense	$ 59,519	66,462	60,812

The total fair value of the Company's vested equity awards for the years ended December 31, 2023, 2024 and 2025 were $75 million, $74 million and $74 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. 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, 2023, 2024 and 2025 were $25.90, $26.52 and $33.64, 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, 2024	3,035,362	$ 26.05
Granted	1,138,906	33.64
Vested	(1,697,987)	25.85
Forfeited	(139,880)	29.85
Total awarded and unvested—December 31, 2025	2,336,401	$ 29.67

As of December 31, 2025, there was $42 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 2020, the Company granted PSU awards to certain of its executive officers that vested based on Antero Resources' absolute total shareholder return ("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. The performance conditions for each of the performance periods ended April 15, 2021, 2022 and 2023 were met. During the year ended December 31, 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. The performance condition for each of the performance periods ended April 15, 2021, 2022 and 2023 were met. During the year ended December 31, 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 was recognized on a graded-vested basis over the term of each performance 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. The performance conditions for each of the performance periods ended April 15, 2022 and 2024 were met at 200% of target, and during the year ended December 31, 2024, the 2021 Absolute TSR PSUs vested and converted into approximately 0.3 million shares of common stock.

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 could ultimately be earned following the end of the cumulative three-year performance period with respect to the 2022 Absolute TSR PSUs ranged from zero to 200% of the target number of 2022 Absolute TSR PSUs originally granted. Expense related to these PSUs was recognized on a graded-vested basis over the term of each performance period. The performance conditions for the performance periods ended April 15, 2023, 2024 and 2025 were met cumulatively at 110% of target. During the year ended December 31, 2025, the 2022 Absolute TSR PSUs vested and converted into approximately 0.2 million shares of common stock.

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 was recognized on a graded-vested basis over the term of each performance period. The performance conditions for the performance periods ended December 31, 2023, 2024 and 2025 were met cumulatively at 82% of target. During the first quarter of 2026, the Special 2022 Absolute TSR PSUs will vest and convert into approximately 0.1 million shares of common stock.

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. The performance condition for the performance period ended March 7, 2024 was not met, and as a result, no vesting for this award tranche was achieved. The performance conditions for the performance period ended March 7, 2025 was met at 200% of target.

In 2024, 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, 2025, March 7, 2026 and March 7, 2027, and one cumulative three-year performance period ending on March 7, 2027, in each case, subject to certain continued employment criteria ("2024 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 2024 Absolute TSR PSUs ranges from zero to 200% of the target number of 2024 Absolute TSR PSUs originally granted. Expense related to these PSUs is recognized on a graded-vested basis over the term of each performance period. The performance conditions for the performance period ended March 7, 2025 was met at 200% of target.

In March 2025, 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, 2026, March 7, 2027 and March 7, 2028, and one cumulative three-year performance period ending on March 7, 2028, in each case, subject to certain continued employment criteria for each performance period ("2025 Absolute TSR PSUs"). The 2025 Absolute TSR PSUs will be settled following the end of each performance period. The aggregate number of shares of common stock that may ultimately be earned with respect to the 2025 Absolute TSR PSUs ranges from zero to 200% of the target number of 2025 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 each of the performance periods ended December 31, 2021, 2022 and 2023 were met at 200% of target. During the year ended December 31, 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 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, 2022, 2023 and 2024 were met cumulatively at 194% of target. During the year ended December 31, 2025, the 2022 Leverage Ratio PSUs vested and converted into approximately 0.3 million shares of common stock.

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 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, 2023, 2024 and 2025 were met cumulatively at 194% of target. During the first quarter of 2026, the Special 2022 Leverage Ratio PSUs will vest and convert into approximately 0.3 million shares of common stock.

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 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, 2023, 2024 and 2025 were met cumulatively at 194% of target. During the first quarter of 2026, the 2023 Leverage Ratio PSUs will vest and convert into approximately 0.4 million shares of common stock.

In 2024, 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, 2024 December 31, 2025 and December 31, 2026, in each case, subject to certain continued employment criteria ("2024 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 2024 Leverage Ratio PSUs ranges from zero to 200% of the target number of 2024 Leverage Ratio PSUs originally granted. Expense related to the 2024 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 each of the performance periods ended December 31, 2024 and 2025 were met at 181% and 200%, respectively, of target.

In March 2025, the Company granted PSUs to certain of its senior management and executive officers that vest based on the Company's Net Debt to 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, 2025, December 31, 2026 and December 31, 2027, in each case, subject to certain continued employment criteria for each performance period ("2025 Leverage Ratio PSUs"). The 2025 Leverage Ratio PSUs will be settled following the end of each performance period. The aggregate number of shares of common stock that may ultimately be earned with respect to the 2025 Leverage Ratio PSUs ranges from zero to 200% of the target number of 2025 Leverage Ratio PSUs originally granted. Expense related to the 2025 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, 2025 was met at 200% of target.

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, 2024	1,351,295	$ 35.27
Granted	289,370	34.33
Vested [(1)]	(281,318)	41.41
Total awarded and unvested—December 31, 2025	1,359,347	$ 33.80

(1) During the year ended December 31, 2025, the 2022 Absolute TSR PSUs and 2022 Leverage Ratio PSUs met the performance criteria to achieve vesting at 110% and 194% of target, respectively, and converted into approximately 0.5 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 leverage ratio-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, 2023, 2024 and 2025 were $28.51, $29.39 and $34.33, 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,		
	2023	2024	2025
Dividend yield	— %	— %	— %
Volatility	82 %	55 %	48 %
Risk-free interest rate	4.61 %	4.23 %	3.97 %
Weighted average fair value of awards granted	$ 33.96	32.29	35.01

As of December 31, 2025, there was $10 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) Stock Options

Stock options granted under the 2013 Plan had a maximum contractual life of 10 years. Expense related to stock options was recognized on a straight-line basis over the requisite service period of the entire award. 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, 2024	252,451	$ 50.00	0.3	$ —
Expired	(252,451)	50.00	—	—
Outstanding—December 31, 2025	—	$ —	—	—
Vested—December 31, 2025	—	$ —	—	$ —
Exercisable—December 31, 2025	—	$ —	—	$ —

(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 was 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 restricted cash, accounts receivable and accounts payable as of December 31, 2024 and 2025 approximated fair value because of their short-term nature. The carrying values of the amounts outstanding under the Unsecured Credit Facility as of December 31, 2024 and 2025 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 (in thousands):

	December 31, 2024		December 31, 2025	
	Fair Value (1)	Carrying Value (2)	Fair Value (1)	Carrying Value (2)
2026 Notes	$ 98,924	96,599	—	—
2029 Notes	417,211	404,055	370,431	363,204
2030 Notes	579,660	595,376	607,500	596,172
Total	$ 1,095,795	1,096,030	977,931	959,376

(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 for information regarding the fair value of equity based awards. See Note 11—Derivative Instruments 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 commodity derivative contracts that settled during the years ended December 31, 2023, 2024 and 2025. The Company enters into derivative contracts when management believes that favorable future sales prices for the Company’s production can be secured. Under the Company’s 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. Under the Company’s basis swap contracts, 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. Under the Company’s collar agreements, when actual commodity prices upon settlement are below the floor price provided by the contract, the Company receives the difference from the counterparty. When actual commodity prices upon settlement are above the ceiling 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.

As of December 31, 2025, the Company's fixed price swap positions were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Weighted Average Price
Natural Gas			
January-December 2026	Henry Hub	770,000 MMBtu/day	$ 3.90 /MMBtu
January-December 2026	TETCO M2	10,000 MMBtu/day	3.36 /MMBtu
January-December 2027	Henry Hub	330,000 MMBtu/day	3.98 /MMBtu

As of December 31, 2025, the Company's basis swap positions were as follows:

Commodity / Settlement Period	Index to Basis Differential	Contracted Volume	Weighted Average Hedged Differential
Natural Gas			
January-December 2026	NYMEX to TETCO M2	150,000 MMBtu/day	$ 0.85 /MMBtu

As of December 31, 2025, the Company's collar contract positions were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Weighted Average Ceiling Price	Weighted Average Floor Price
Natural Gas				
January-December 2026	Henry Hub	500,000 MMBtu/day	$ 5.83 /MMBtu	$ 3.22 /MMBtu
January-December 2027	Henry Hub	10,000 MMBtu/day	5.00 /MMBtu	3.50 /MMBtu

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, 2025, 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 2026	Henry Hub	32,000 MMBtu/day	$ 2.63 /MMBtu	$ 2.63 /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. During the year ended December 31, 2023, the Company executed an early settlement of this swaption agreement and made a cash payment of $202 million.

During the year ended December 31, 2025, all of Martica's derivative contracts expired. As of December 31, 2025, Martica had no derivative instruments.

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

(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, 2024	December 31, 2025
Asset derivatives not designated as hedges for accounting purposes:			
Commodity derivatives—current	Derivative instruments	$ —	68,054
Embedded derivatives—current	Derivative instruments	1,050	859
Commodity derivatives—noncurrent	Derivative instruments	—	12,524
Embedded derivatives—noncurrent	Derivative instruments	1,296	—
Total asset derivatives (1)		2,346	81,437
Liability derivatives not designated as hedges for accounting purposes:			
Commodity derivatives—current (2)	Derivative instruments	31,792	—
Commodity derivatives—noncurrent	Derivative instruments	17,233	—
Total liability derivatives (1)		49,025	—
Net derivatives asset (liability) (1)		$ (46,679)	81,437

(1) The fair value of derivative instruments was determined using Level 2 inputs.
(2) As of December 31, 2024, $2 million of current commodity derivative liabilities 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, 2024			December 31, 2025		
	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	$ 3,482	(3,482)	—	162,641	(82,063)	80,578
Embedded derivative assets	2,346	—	2,346	859	—	859
Commodity derivative liabilities	(52,507)	3,482	(49,025)	(82,063)	82,063	—

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 (in thousands):

	Statement of Operations Location	Year Ended December 31, 2023	2024	2025
Commodity derivative fair value gains (1)	Revenue	$ 165,448	2,846	112,536
Embedded derivative fair value gains (losses) (1)	Revenue	876	(2,115)	(1,487)

(1) The fair value of derivative instruments was determined using Level 2 inputs.

Commodity derivative fair value gains (losses) for the year ended December 31, 2023 includes losses of $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 year ended December 31, 2023. There were no early settlements of commodity derivatives during the years ended December 31, 2024 and 2025.

(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.

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

(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, 2024	December 31, 2025
Operating Leases			
Operating lease right-of-use assets:			
Processing plants	Operating lease right-of-use assets	$ 1,365,582	1,135,203
Drilling rigs and completion services	Operating lease right-of-use assets	—	54,968
Gas gathering lines and compressor stations [(1)]	Operating lease right-of-use assets	1,149,981	912,073
Office space	Operating lease right-of-use assets	33,345	28,400
Office, field and other equipment	Operating lease right-of-use assets	490	1,865
Total operating lease right-of-use assets		$ 2,549,398	2,132,509
Operating lease liabilities:			
Short-term operating lease liabilities	Short-term lease liabilities	$ 492,624	514,717
Long-term operating lease liabilities	Long-term lease liabilities	2,048,942	1,610,341
Total operating lease liabilities		$ 2,541,566	2,125,058
Finance Leases			
Finance lease right-of-use assets:			
Vehicles	Other property and equipment	$ 2,665	3,486
Total finance lease right-of-use assets [(2)]		$ 2,665	3,486
Finance lease liabilities:			
Short-term finance lease liabilities	Short-term lease liabilities	$ 1,270	1,539
Long-term finance lease liabilities	Long-term lease liabilities	1,395	1,947
Total finance lease liabilities		$ 2,665	3,486

(1) Gas gathering lines and compressor stations relate to Antero Midstream. See "—Related party lease disclosure" for additional information.
(2) Financing lease assets are recorded net of accumulated amortization of $3 million as of December 31, 2024 and 2025.

The processing plants, gathering lines and compressor stations that are classified as lease liabilities are classified as such under FASB ASC Topic 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.

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

(b) Supplemental Information Related to Leases

Costs associated with operating and finance leases were included in the consolidated financial statements as follows (in thousands):

			Year Ended December 31,		
Cost	**Classification**	**Location**	**2023**	**2024**	**2025**
Operating lease cost	Statement of operations	Gathering, compression, processing and transportation	$ 1,623,268	1,721,981	1,619,284
Operating lease cost	Statement of operations	General and administrative	12,121	12,345	12,881
Operating lease cost	Statement of operations	Contract termination, loss contingency and settlements	4,227	—	—
Operating lease cost	Statement of operations	Lease operating	84	148	1,077
Operating lease cost	Balance sheet	Proved properties [1]	160,638	131,623	37,721
Total operating lease cost			$ 1,800,338	1,866,097	1,670,963
Finance lease cost:					
Amortization of right-of-use assets	Statement of operations	Depletion, depreciation and amortization	$ 1,530	1,639	1,768
Interest on lease liabilities	Statement of operations	Interest expense	597	522	520
Total finance lease cost			$ 2,127	2,161	2,288
Short-term lease payments			$ 137,781	109,874	154,079

(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,		
	2023	**2024**	**2025**
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$ 1,366,677	1,492,421	1,606,289
Operating cash flows from finance leases	597	522	520
Investing cash flows from operating leases	126,483	97,984	22,072
Financing cash flows from finance leases	830	1,106	1,538
Noncash activities:			
Right-of-use assets obtained in exchange for new operating lease obligations	$ 76,797	97,866	166,711
Decrease to existing right-of-use assets and lease obligations from operating lease modifications, net [1]	$ (15,858)	20,911	(14,435)

(1) 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. During the year ended December 31, 2024, the weighted average discount rate for remeasured operating leases decreased from 6.5% as of December 31, 2023 to 5.5% as of December 31, 2024. During the year ended December 31, 2025, the weighted average discount rate for remeasured operating leases increased from 5.5% as of December 31, 2024 to 5.8% as of December 31, 2025.

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

(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, 2025 (in thousands):

	Operating Leases	Financing Leases	Total
2026	$ 642,419	2,036	644,455
2027	487,275	1,064	488,339
2028	406,177	891	407,068
2029	322,110	373	322,483
2030	248,965	—	248,965
Thereafter	408,821	—	408,821
Total lease payments	2,515,767	4,364	2,520,131
Less: imputed interest	(345,884)	(681)	(346,565)
Total	$ 2,169,883	3,683	2,173,566

(e) Lease Term and Discount Rate

The following table sets forth the Company's weighted average remaining lease term and discount rate:

	December 31, 2024		December 31, 2025	
	Operating Leases	Finance Leases	Operating Leases	Finance Leases
Weighted average remaining lease term	6.0 years	2.1 years	5.4 years	2.8 years
Weighted average discount rate	5.5 %	8.4 %	5.6 %	8.5 %

(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 in 2022 of certain Marcellus gathering and compression assets in an area of dedication (the "Marcellus gathering and compression agreement") and (iii) a compression agreement from Antero Midstream's acquisition in 2022 of certain Utica compressors (the "Utica compression agreement") and (iv) a gathering and compression agreement from Antero Midstream's acquisition in the second quarter of 2024 of certain central Marcellus gathering and compression assets (the "Mountaineer gathering and compression agreement," and together with the 2019 gathering and compression agreement, Marcellus gathering and compression agreement and the Utica 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, Marcellus gathering and compression agreement and Mountaineer gathering and compression agreement have initial terms through 2038, 2031 and 2026, respectively, and the Utica compression agreement has one remaining acreage dedication that expires in 2030. The Utica compression agreement will be assumed by the Buyer Parties at the closing of the Utica Shale Divestiture. Upon expiration of the Marcellus gathering and compression agreement, Utica compression agreement and Mountaineer gathering and 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. 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 Mountaineer gathering and compression agreement provides for monthly minimum compression and gathering fees for each compressor station or high pressure gathering line, respectively, for a period of 12 years commencing 90 days after such asset's in-service date. As of December 31, 2025, the minimum volume commitments for the 2019 gathering and compression agreement end in 2035, and the minimum compression and gathering fees for the Mountaineer gathering and compression agreement end in 2026. As of January 1, 2025, there were no minimum volume commitments under the Marcellus gathering and compression agreement.

The 2019 gathering and compression agreement included a growth incentive fee program that expired on December 31, 2023 whereby low pressure gathering fees were reduced from 2020 through 2023 to the extent the Company achieved certain quarterly volumetric targets. Only the Company's throughput gathered under the 2019 gathering and compression agreement was considered in the low pressure gathering volume target. The Company earned fee rebates for the year ended December 31, 2023 of $52 million.

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 notice from either the Company or Antero Midstream to the other party on or before the 180th day prior to the anniversary of such agreement

For the years ended December 31, 2023, 2024 and 2025, gathering and compression fees paid by Antero related to these agreements were $738 million, $813 million and $848 million, respectively. As of December 31, 2024 and 2025, $79 million and $85 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,		
	2023	**2024**	**2025**
Current:			
State	$ 1,587	455	1,902
Current income tax expense	1,587	455	1,902
Deferred:			
U.S. federal	50,969	(107,890)	192,252
State	11,070	(10,750)	21,713
Deferred income tax expense (benefit)	62,039	(118,640)	213,965
Total income tax expense (benefit)	$ 63,626	(118,185)	215,867

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

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, except percentages):

	Year Ended December 31,					
	2023		2024		2025	
	Amount	Percent	Amount	Percent	Amount	Percent
U.S. federal statutory income tax	$ 75,801	21.0 %	$ (5,143)	21.0 %	$ 186,991	21.0 %
State and local income tax, net of U.S. federal effect [1]	12,657	3.5 %	(10,295)	42.0 %	23,215	2.6 %
Tax credits						
Research and development	—	— %	(148,861)	607.9 %	(4,375)	(0.5)%
Nontaxable or nondeductible items						
Executive compensation	2,279	0.6 %	5,184	(21.2)%	13,515	1.5 %
Other	439	0.1 %	1,037	(4.2)%	431	— %
Changes in unrecognized tax benefits	—	— %	53,590	(218.8)%	(2,663)	(0.3)%
Other items						
Noncontrolling interests	(20,774)	(5.8)%	(7,659)	31.3 %	(8,431)	(0.9)%
Dividends received deduction	(3,075)	(0.9)%	(4,785)	19.5 %	(6,155)	(0.7)%
Equity-based compensation	(3,030)	(0.8)%	(2,390)	9.8 %	(1,786)	(0.2)%
NOL adjustments	—	— %	980	(4.0)%	15,186	1.7 %
Other	(671)	(0.2)%	157	(0.6)%	(61)	— %
Total income tax expense (benefit) / Effective tax rate	$ 63,626	17.5 %	$ (118,185)	482.7 %	$ 215,867	24.2 %

(1) Pennsylvania made up the majority (greater than 50 percent) of the Company's state income tax expense, net of the federal effect for the years ended December 31, 2023, 2024 and 2025.

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,	
	2024	2025
Deferred income tax assets:		
NOL carryforwards	$ 212,289	266,123
Research and development tax credits, net	95,271	102,309
Interest expense carryforwards	46,452	9,516
Equity-based compensation	6,462	4,132
Investment in Antero Midstream	214,357	194,960
Unrealized losses on derivative instruments	9,863	—
Lease liabilities	555,264	477,262
Asset retirement obligations and other	23,080	29,247
Total deferred income tax assets	1,163,038	1,083,549
Valuation allowance	(43,192)	(39,112)
Deferred income tax assets, net	1,119,846	1,044,437
Deferred income tax liabilities:		
Oil and gas properties	1,229,297	1,439,666
Unrealized gains on derivative instruments	—	17,912
Lease right-of-use assets	556,976	478,901
Investment in Martica	24,808	13,837
Other	2,106	1,427
Total deferred income tax liabilities	1,813,187	1,951,743
Deferred tax liability, net	$ (693,341)	(907,306)

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

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 $43 million and $39 million as of December 31, 2024 and 2025, respectively. The valuation allowance for each of the years ended December 31, 2024 and 2025 relates primarily to Colorado and Oklahoma state NOL carryforwards and is 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.

As of December 31, 2025, the Company has U.S. federal and state NOL carryforwards of approximately $960 million 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 in 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 after 2020 expire between 2026 and 2044. The Colorado NOL Carryforwards generated in tax years 2018 through 2020 have no expiration date. As of December 31, 2025, the Company has U.S. federal income tax credits of $153 million, excluding related reserves, which expire between 2033 and 2045.

Tax years 2022 through 2025 remain open to examination by the IRS. The Company and its subsidiaries file tax returns with various state taxing authorities, and those returns remain open to examination for tax years 2021 through 2025.

The Company commissioned a multi-year R&D tax credit study related to the Company's drilling and completion methods that resulted in a favorable adjustment to the Company's effective tax rate and future tax obligations. The recorded net R&D tax credit, as of December 31, 2025, expected to be utilized in future periods is $102 million. The R&D tax credits expire between 2033 and 2045.

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 IRS or state revenue authorities. The recognition of the unrecognized tax benefit reported by the Company would affect its effective tax rate.

The reserve for uncertain tax positions, excluding interest and penalties, is as follows (in thousands):

	Year Ended December 31,		
	2023	**2024**	**2025**
Beginning balance	$ —	—	53,590
Tax positions taken in current year	—	53,590	—
Tax positions taken in the prior year	—	—	(2,663)
Ending balance	$ —	53,590	50,927

(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, 2025 (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
2026	$ 1,209,447	32,988	537,006	107,449	17,033	1,903,923
2027	1,203,840	31,699	407,607	80,732	6,088	1,729,966
2028	1,141,428	30,366	347,739	59,329	2,578	1,581,440
2029	785,642	29,857	281,002	41,481	68	1,138,050
2030	695,409	29,121	221,794	27,171	—	973,495
Thereafter	2,988,374	53,356	378,418	30,403	—	3,450,551
Total	$ 8,024,140	207,387	2,173,566	346,565	25,767	10,777,425

(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.

The Company's firm transportation commitments include $220 million related to 300,000 MMBtu/d of REX firm capacity that will be assumed by the Buyer Parties upon the closing of the Utica Shale Divestiture and FERC approval. See Note 3—Transactions for additional information.

(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. The Company's operating and finance lease commitments do not include obligations for leases that have not yet commenced.

The Company's future minimum payments for operating and finance leases, including imputed interest, includes $48 million related to contracts that will be assumed by the Buyer Parties at the closing of the Utica Shale Divestiture, which are classified as held for sale as of December 31, 2025. See Note 3—Transactions for additional information.

(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, loss contingency and settlements included in the statements of operations and comprehensive income. 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, 2025.

(15) Contingencies

(a) 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.

(b) Production Taxes

The Company is subject to production taxes in the states in which it operates. The Company's production tax filings in West Virginia for 2018 to 2020 tax years were subject to audit by the State of West Virginia. All assessments received in conjunction with this audit were recorded in the consolidated statement of operations and comprehensive net loss during the year ended December 31, 2024; however, the Company has filed an appeal with regard to such assessments. At this time, the Company believes the outcome of this matter will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

(c) Other

The Company is party to various legal proceedings and claims in the ordinary course of its business. The Company evaluates its legal proceedings on a regular basis and accrues a liability for such matters when the Company believes that a loss is probable and the amount of the loss can be reasonably estimated. Any such accruals are adjusted thereafter to reflect changed circumstances. In the event the Company determines that (i) a loss to the Company is probable but the amount of the loss cannot be reasonably estimated, or (ii) a loss to the Company is less likely than probable but is reasonably possible, then the Company is required to disclose the matter herein, although the Company is not required to accrue such loss.

When able, the Company determines an estimate of reasonably possible losses or ranges of reasonably possible losses, whether in excess of any related accrued liability or where there is no accrued liability, for legal proceedings. In instances where such estimates can be made, any such estimates are based on the Company's analysis of currently available information and are subject to significant judgment and a variety of assumptions and uncertainties and may change as new information is obtained. The Company could also be responsible for interest on any amount the Company may be determined to owe, the amount of which is not determinable or estimable. The ultimate outcome of the matters described above, such as whether the likelihood of loss is remote, reasonably possible, or probable, or if and when the range of loss is reasonably estimable, is inherently uncertain. Furthermore, due to the inherent subjectivity of the assessments and unpredictability of outcomes of legal proceedings, any amounts accrued or estimated as possible losses may not represent the ultimate loss to the Company from the legal proceedings in question and the Company's exposure and ultimate losses may be higher than the amounts accrued or estimated.

The Company has been named in various lawsuits alleging royalty underpayments, some of which seek class action certification. Pending litigation against the Company and other peer operators could have an impact on the methods for determining royalty payments due to lessors under oil and gas leases, including 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, many of these proceedings are in early stages, involve multiple lease forms with varying royalty provisions and seek or may seek damages the amount of which is currently indeterminate. In a class action lawsuit to which the Company is a party, Jacklin Romeo, et al. v. Antero Resources Corporation, the U.S. District Court for the Northern District of West Virginia certified certain questions to the West Virginia Supreme Court (the "WVSC") with respect to the interpretation of West Virginia's implied duty to market gas where a lease lacks any express language regarding the allocation of post-production costs and the treatment of NGLs. The WVSC answered the certified questions in November 2024; however, in December 2024, Antero petitioned the WVSC for rehearing on the certified questions, which stayed the issuance of the mandate required for the November 2024 opinion to take effect. The petition for rehearing was granted by the WVSC on December 31, 2024, and oral argument on the matter was held before the WVSC on April 22, 2025. On June 11, 2025, the WVSC answered the certified questions, the effect of which broadens the scope of products for which the Company will pay royalties and limits the amount of post-production costs the Company deducts from royalty payments, in each case, under leases that do not contain language to the contrary. With respect to the Romeo matter, the Company has accrued an immaterial amount as of December 31, 2025 for estimated damages that is recorded in contract termination, loss contingency and settlements in the consolidated statements of operations and comprehensive income.

The WVSC's answers to the certified questions in the Romeo matter could also impact past royalty payments made by the Company, as well as royalty payments owed in the future, under certain of the Company's other leases that are not at issue in the Romeo matter. While the Company cannot predict with certainty the timing and ultimate outcome of any other currently pending claims or potential other claims relating to royalty payments under such other leases, the Company currently estimates the amount of losses that are reasonably possible associated with such other leases, could be up to $400 million.

Rulings were also previously received in two other 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 based on interpretation of specific language in the applicable leases: 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, 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 and when the foregoing issues may ultimately be resolved, and therefore is also unable to estimate potential damages, if any, that may result.

(16) Related Parties

Substantially all of Antero Midstream's revenues were and are derived from transactions with Antero Resources. See Note 12—Leases for additional information on the Company's related party leases. See Note 17—Reportable Segments 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) exploration and production; (ii) the Company's equity method investment in Antero Midstream and (iii) marketing. 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 (including the expertise required for these operations), production processes, customers and distribution methods. The Company's Chief Executive Officer and President was determined to be the Company's chief operating decision maker ("CODM"). The CODM evaluates the performance of the Company's business segments based on operating income (loss). The CODM considered the Company's actual operating income (loss) as compared to the operating income (loss) for (i) the relevant prior period actual results, (ii) budget and (iii) guidance on a monthly basis for purposes of evaluating performance of each segment and making decisions about allocating capital and other resources to each segment.

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 (expense), 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.

Equity Method Investment in Antero Midstream

The Company receives midstream services through its equity method investment in Antero Midstream. Antero Midstream is a related party, and the Company's CODM also serves as the CODM for 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.

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.

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Notes to Consolidated Financial Statements (Continued)

(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, 2023				
	Exploration and Production	**Marketing**	**Equity Method Investment in Antero Midstream (1)**	**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 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
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
Facility idling	—	—	2,459	(2,459)	—
Depletion, depreciation and amortization	746,849	—	136,059	(136,059)	746,849
Impairment of property and equipment	51,302	—	146	(146)	51,302
Other (2)	34,676	23,763	7,012	(7,012)	58,439
Total operating expenses	3,976,997	308,728	429,909	(429,909)	4,285,725
Operating income (loss)	$ 498,853	(102,606)	611,862	(611,862)	396,247
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

(1) Amounts reflect those recorded in Antero Midstream Corporation's consolidated financial statements.
(2) Amounts include charges for exploration expenses, accretion of asset retirement obligations, loss on settlement of asset retirement obligations, contract termination, loss contingency and settlements, loss (gain) on sale of assets, as applicable, which represent segment operating expenses that are not considered significant.

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Notes to Consolidated Financial Statements (Continued)

	Year Ended December 31, 2024				
	Exploration and Production	**Marketing**	**Equity Method Investment in Antero Midstream [1]**	**Elimination of Unconsolidated Affiliate**	**Consolidated Total**
Sales and revenues:					
Third-party	$ 4,144,229	179,069	1,944	(1,944)	4,323,298
Intersegment	2,298	—	1,104,249	(1,104,249)	2,298
Total revenue	4,146,527	179,069	1,106,193	(1,106,193)	4,325,596
Operating expenses:					
Lease operating	118,693	—	—	—	118,693
Gathering and compression	897,160	—	103,053	(103,053)	897,160
Processing	1,069,887	—	—	—	1,069,887
Transportation	735,883	—	—	—	735,883
Water handling	—	—	114,923	(114,923)	—
Production and ad valorem taxes	207,671	—	—	—	207,671
Marketing	—	244,906	—	—	244,906
General and administrative (excluding equity-based compensation)	162,876	—	41,754	(41,754)	162,876
Equity-based compensation	66,462	—	44,332	(44,332)	66,462
Facility idling	—	—	1,721	(1,721)	—
Depletion, depreciation and amortization	762,068	—	140,000	(140,000)	762,068
Impairment of property and equipment	47,433	—	332	(332)	47,433
Other [2]	12,097	—	912	(912)	12,097
Total operating expenses	4,080,230	244,906	447,027	(447,027)	4,325,136
Operating income (loss)	$ 66,297	(65,837)	659,166	(659,166)	460
Equity in earnings of unconsolidated affiliates	$ 93,787	—	110,573	(110,573)	93,787
Capital expenditures for segment assets	$ 716,779	—	172,347	(172,347)	716,779

(1) Amounts reflect those recorded in Antero Midstream Corporation's consolidated financial statements.
(2) Amounts include charges for exploration expenses, accretion of asset retirement obligations, loss on settlement of asset retirement obligations, contract termination, loss contingency and settlements, loss (gain) on sale of assets and other operating expenses, as applicable, which represent segment operating expenses that are not considered significant.

ANTERO RESOURCES CORPORATION
Notes to Consolidated Financial Statements (Continued)

	Year Ended December 31, 2025				
	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream (1)	Elimination of Unconsolidated Affiliate	Consolidated Total
Sales and revenues:					
Third-party	$ 5,147,647	125,900	2,415	(2,415)	5,273,547
Intersegment	2,276	—	1,186,011	(1,186,011)	2,276
Total revenue	5,149,923	125,900	1,188,426	(1,188,426)	5,275,823
Operating expenses:					
Lease operating	135,124	—	—	—	135,124
Gathering and compression	946,900	—	107,846	(107,846)	946,900
Processing	1,125,358	—	—	—	1,125,358
Transportation	785,168	—	—	—	785,168
Water handling	—	—	124,064	(124,064)	—
Production and ad valorem taxes	163,135	—	—	—	163,135
Marketing	—	190,206	—	—	190,206
General and administrative (excluding equity-based compensation)	171,714	—	41,976	(41,976)	171,714
Equity-based compensation	60,812	—	45,958	(45,958)	60,812
Facility idling	—	—	1,801	(1,801)	—
Depletion, depreciation and amortization	749,675	—	134,310	(134,310)	749,675
Impairment of property and equipment	29,358	—	984	(984)	29,358
Loss on long-lived assets	—	—	86,626	(86,626)	—
Other (2)	34,727	—	192	(192)	34,727
Total operating expenses	4,201,971	190,206	543,757	(543,757)	4,392,177
Operating income (loss)	$ 947,952	(64,306)	644,669	(644,669)	883,646
Equity in earnings of unconsolidated affiliates	$ 98,484	—	116,439	(116,439)	98,484
Capital expenditures for segment assets	$ 820,122	—	162,255	(162,255)	820,122

(1) Amounts reflect those recorded in Antero Midstream Corporation's consolidated financial statements.
(2) Amounts include charges for exploration expenses, accretion of asset retirement obligations, contract termination, loss contingency and settlements, loss (gain) on sale of assets and other operating expenses, as applicable, which represent segment operating expenses that are not considered significant.

	As of December 31, 2024				
	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream (1)	Elimination of Unconsolidated Affiliate	Consolidated Total
Investments in unconsolidated affiliates	$ 231,048	—	603,956	(603,956)	231,048
Total assets	12,999,930	10,120	5,761,748	(5,761,748)	13,010,050

(1) Amounts reflect those recorded in Antero Midstream Corporation's consolidated financial statements.

	As of December 31, 2025				
	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream (1)	Elimination of Unconsolidated Affiliate	Consolidated Total
Investments in unconsolidated affiliates	$ 245,653	—	585,778	(585,778)	245,653
Total assets	13,238,013	7,394	5,884,116	(5,884,116)	13,245,407

(1) Amounts reflect those recorded in Antero Midstream Corporation's consolidated financial statements.

(18) 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,	
	2024	**2025**
Unproved properties	$ 879,483	796,705
Proved properties	14,395,680	14,049,003
Total oil and gas properties	15,275,163	14,845,708
Accumulated depletion	(5,625,419)	(5,674,702)
Net capitalized costs (1)	$ 9,649,744	9,171,006

(1) Net capitalized costs does not include $706 million related to the Utica Shale Properties held for sale as of December 31, 2025, including $28 million for unproved property, $1.0 billion of proved property and $367 million of accumulated depletion. See Note 3—Transactions for additional information.

(b) Costs Incurred in Certain Oil and Gas Activities

	Year Ended December 31,		
	2023	**2024**	**2025**
Acquisition costs:			
Unproved property	$ 151,135	90,995	129,247
Development costs	956,267	614,855	677,633
Exploration costs	8,079	—	7,836
Total costs incurred	$ 1,115,481	705,850	814,716

(c) Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2023	**2024**	**2025**
Revenues	$ 4,276,445	4,115,299	5,010,239
Operating expenses:			
Production expenses	2,919,654	3,029,294	3,155,685
Exploration expenses	2,691	2,618	2,990
Depletion	738,992	754,010	741,685
Impairment of unproved properties	51,302	47,433	29,358
Results of operations before income taxes	563,806	281,944	1,080,521
Income tax (expense) benefit (1)	(122,695)	33,653	(230,971)
Results of operations	$ 441,111	315,597	849,550

(2) Income tax (expense) benefit includes R&D tax credits of $95 million and $7 million for the years ended December 31, 2024 and 2025, respectively, since such credits directly relate to the Company's oil and gas producing activities.

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Notes to Consolidated Financial Statements (Continued)

(d) Oil and Gas Reserves

Net proved oil and gas reserves for the years ended December 31, 2023, 2024 and 2025 were prepared by the Company's reserve engineers and audited by 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, 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
Revisions	265	31	(2)	435
Extensions, discoveries and other additions	651	21	1	783
Divestitures of reserves	(134)	(8)	(1)	(184)
Production	(793)	(73)	(4)	(1,252)
December 31, 2024 [1]	10,603	1,193	23	17,903
Revisions	1,140	32	1	1,331
Extensions, discoveries and other additions	553	18	1	665
Acquisition of reserves	282	37	—	506
Production	(808)	(72)	(3)	(1,256)
December 31, 2025 [1]	11,770	1,208	22	19,149

(1) 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. Proved reserves for the noncontrolling interests in Martica as of December 31, 2024 were 57 Bcfe, which consisted of 44 Bcf of natural gas and 2 MMBbl of NGLs. Proved reserves for the noncontrolling interests in Martica as of December 31, 2025 were 38 Bcfe, which consisted of 30 Bcf of natural gas and 1 MMBbl of NGLs.

	Natural Gas (Bcf)	NGLs (MMBbl)	Oil and Condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2023 (1)	7,912	963	15	13,783
December 31, 2024 (1)	7,876	966	13	13,747
December 31, 2025 (1)	8,388	1,003	12	14,478
Proved undeveloped reserves:				
December 31, 2023 (2)	2,702	259	14	4,338
December 31, 2024 (2)	2,727	227	10	4,156
December 31, 2025 (2)	3,382	205	10	4,671

(1) 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. Proved developed reserves for the noncontrolling interests in Martica as of December 31, 2024 were 57 Bcfe, which consisted of 44 Bcf of natural gas and 2 MMBbl of NGLs. Proved developed reserves for the noncontrolling interests in Martica as of December 31, 2025 were 38 Bcfe, which consisted of 30 Bcf of natural gas and 1 MMBbl of NGLs.
(2) There were no proved undeveloped reserves for the noncontrolling interests in Martica as of December 31, 2023, 2024 and 2025.

2023 Proved Reserve Changes

Significant changes in proved reserves for the year ended December 31, 2023 include the following:

- 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:
  - Net upward revisions of previous estimates of 814 Bcfe primarily due to increases in the Company's ownership interests.
  - 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.
  - Downward revisions of 81 Bcfe due to decreases in prices for natural gas, NGLs and oil.

2024 Proved Reserve Changes

Significant changes in proved reserves for the year ended December 31, 2024 include the following:

- Extensions, discoveries, and other additions of 783 Bcfe resulted from delineation and development drilling in the Appalachian Basin.
- Net upward revisions of 435 Bcfe include:
  - Net upward revisions of previous estimates of 305 Bcfe primarily due to increases in the Company's ownership interests.
  - Net upward revision of 207 Bcfe related to optimization to the Company's five-year development plan. This figure includes upward revisions of 416 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 209 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
  - Downward revisions of 77 Bcfe due to decreases in prices for natural gas and oil, partially offset by increases in prices for NGLs.

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2025 Proved Reserve Changes

Significant changes in proved reserves for the year ended December 31, 2025 include the following:

- Extensions, discoveries, and other additions of 665 Bcfe resulted from delineation and development drilling in the Appalachian Basin.
- Net upward revisions of 1,331 Bcfe include:
  - Net upward revisions of previous estimates of 451 Bcfe primarily due to increases in the Company's ownership interests.
  - Net upward revision of 743 Bcfe related to optimization to the Company's five-year development plan. This figure includes upward revisions of 1,045 Bcfe primarily 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 302 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
  - Upward revisions of 137 Bcfe due to increases in prices for natural gas and ethane, partially offset by decreases in prices for C3+ NGLs and oil.
- Acquisition of reserves of 506 Bcfe related to the Company's acquisitions of additional working and royalty interests in certain Antero-operated producing wells for the year ended December 31, 2025.

(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 arithmetic average 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,		
	2023	2024	2025
Future cash inflows	$ 58,061	52,995	71,879
Future production costs	(41,887)	(41,583)	(46,541)
Future development costs	(2,027)	(2,028)	(2,560)
Future net cash flows before income tax	14,147	9,384	22,778
Future income tax expense	(2,178)	(1,036)	(4,017)
Future net cash flows	11,969	8,348	18,761
10% annual discount for estimated timing of cash flows	(6,874)	(4,853)	(10,651)
Standardized measure of discounted future net cash flows (1)	$ 5,095	3,495	8,110

(1) The standardized measure of discounted future net cash flows for the noncontrolling interests in Martica were $170 million, $101 million and $72 million for the years ended December 31, 2023, 2024 and 2025, respectively.

The Company used the following 12-month weighted average prices to estimate its total equivalent reserves (per Mcfe):

	Year Ended December 31,		
	2023	2024	2025
12-month weighted average price	$ 3.20	2.96	3.75

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Notes to Consolidated Financial Statements (Continued)

(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,		
	2023	2024	2025
Sales of oil and gas, net of productions costs	$ (1,357)	(1,086)	(1,855)
Net changes in prices and production costs [1]	(25,672)	(2,231)	6,053
Development costs incurred during the period	637	512	511
Net changes in future development costs	(96)	(117)	(207)
Extensions, discoveries and other additions	69	121	160
Acquisitions of reserves	—	—	284
Divestitures of reserves	—	(34)	—
Revisions of previous quantity estimates	190	105	769
Accretion of discount	2,947	593	383
Net change in income taxes	5,069	498	(1,233)
Changes in timing and other	(256)	39	(250)
Net increase (decrease)	(18,469)	(1,600)	4,615
Beginning of year	23,564	5,095	3,495
End of year [2]	$ 5,095	3,495	8,110

(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 $2.2 billion, $1.0 billion and $4.0 billion for the years ended December 31, 2023, 2024 and 2025, respectively.
(2) The standardized measure for the noncontrolling interests in Martica were $170 million, $101 million and $72 million for the years ended December 31, 2023, 2024 and 2025, respectively.

Exhibit 4.4

DESCRIPTION OF COMMON STOCK

The following summary of Antero Resources Corporation's ("we," "us," and "our") common stock, par value $0.01 per share, does not purport to be complete and is subject to and qualified by reference to our Amended and Restated Certificate of Incorporation and the Certificate of Amendment to our Amended and Restated Certificate of Incorporation (together, the "Certificate of Incorporation") and Third Amended and Restated Bylaws (the "Bylaws").

Common Stock

Our Certificate of Incorporation authorizes for issuance 1,050,000,000 shares of capital stock consisting of (i) 1,000,000,000 shares of common stock, par value $0.01 per share, and (ii) 50,000,000 shares of preferred stock, par value $0.01 per share.

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock are not entitled to vote on any amendment to the Certificate of Incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to the Certificate of Incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the Delaware General Corporation Law ("DGCL"). Subject to prior rights and preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably in proportion to the shares of common stock held by them such dividends and distributions (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available therefor. All outstanding shares of common stock are fully paid and non-assessable. The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to the common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs, holders of common stock are entitled to share ratably in our assets in proportion to the shares of common stock held by them that are remaining after payment or provision for payment of all of our debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

Anti-Takeover Provisions of Our Certificate of Incorporation and Bylaws

Certain provisions of Delaware law, our Certificate of Incorporation and our Bylaws could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise; or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

Section 203 of the DGCL prohibits a Delaware corporation, including those whose securities are listed for trading on the NYSE, 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:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;

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

We have elected to not be subject to the provisions of Section 203 of the DGCL.

Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws

Among other things, our Certificate of Incorporation and Bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year (unless the date of the annual meeting is more than 30 days before or more than 60 days after such anniversary date, in which case such notice must be delivered no earlier than the close of business on the 120th day prior to such annual meeting or later than the close of business on the later of the 90th day prior to such annual meeting or, if the first public announcement of the date of such annual meeting is less than 100 days prior to the date of such annual meeting, the 10th day after the first public disclosure of the date of such meeting by us). Our Bylaws specify the requirements as to form and content of all stockholders" notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;
- provide our board of directors the ability to authorize undesignated preferred stock. This ability 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. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;
- provide that the authorized number of directors may be changed only by resolution of the board of directors;
- provide that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;
- provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock with respect to such series;
- provide our Certificate of Incorporation and Bylaws may be amended by the affirmative vote of the holders of at least two thirds of our then outstanding common stock;
- provide that special meetings of our stockholders may only be called by the board of directors, the chief executive officer or the chairman of the board;
- 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, other than directors which may be elected by holders of preferred stock, if any. This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;

- provide that we renounce any interest in existing and future investments in other entities by, or the business opportunities of, our private equity sponsors or any of their respective officers, directors, agents, stockholders, members, partners, affiliates and subsidiaries (other than our directors that are presented business opportunities in their capacity as our directors) and that they have no obligation to offer us those investments or opportunities; and

- provide that our Bylaws can be amended or repealed at any regular or special meeting of stockholders or by the board of directors, including the requirement that any amendment by the stockholders at a meeting be upon the affirmative vote of at least 66 2/3% of the shares of common stock generally entitled to vote in the election of directors.

Exhibit 10.23

ANTERO RESOURCES CORPORATION
EXECUTIVE SEVERANCE PLAN
PARTICIPATION AGREEMENT

________, 20__

[NAME]

Re: Participation Agreement – Antero Resources Corporation Executive Severance Plan

Dear [NAME]:

We are pleased to inform you that you have been designated as eligible to participate in the Antero Resources Corporation Executive Severance Plan (as it may be amended from time to time, the "Plan"). Your participation in the Plan is subject to the terms and conditions of the Plan, your execution and delivery of this agreement, which constitutes a Participation Agreement (as defined in the Plan), and your execution and delivery of the Notice of Restrictive Covenants. A copy of the Plan is attached hereto as Annex A and is incorporated herein and deemed to be part of this Participation Agreement for all purposes. A copy of the Notice of Restrictive Covenants is attached hereto as Annex B. Your participation in the Plan shall be effective 14 days following execution of this Participation Agreement and the Notice of Restrictive Covenants.

In signing below, you expressly agree to be bound by, and promise to abide by, the terms of Sections 7, 8, 9, and 10 of the Plan, which create certain restrictions with respect to confidentiality, non-solicitation, non-disparagement and post-termination cooperation. You further acknowledge that receipt of severance benefits following a Qualifying Termination under the Plan is contingent upon your execution of a general release of claims at the time of such Qualifying Termination and continued compliance with, to the extent applicable pursuant to the terms thereof, any restrictive covenants set forth in the Plan.

You acknowledge and agree that the Plan and this Participation Agreement supersede all prior severance benefit policies, plans and arrangements of the Company or any other member of the Resources Group (and supersedes all prior oral or written communications by the Company or any of other member of the Resources Group with respect to severance benefits), and all such prior policies, plans, arrangements and communications are hereby null and void and of no further force and effect with respect to your participation therein; *provided, however,* that the terms and provisions of the AR LTIP, the 2013 AR LTIP, the AM LTIP, and the award agreements under each such plan shall continue to govern the equity-based awards granted under such plans to an Eligible Executive following such Eligible Executive's termination of employment.

You further acknowledge and agree that (i) you have fully read, understand and voluntarily enter into this Participation Agreement and (ii) you have had a sufficient opportunity to consult with your personal tax, financial planning advisor and attorney about the tax, financial and legal consequences of your participation in the Plan before signing this Participation Agreement.

Unless otherwise defined herein, capitalized terms used in this Participation Agreement shall have the meanings set forth in the Plan. This Participation Agreement may be executed in separate counterparts, each of which shall be deemed an original, but all of which taken together shall constitute one and the same instrument.

Please execute this Participation Agreement in the space provided below and send a fully executed copy to Yvette K. Schultz no later than fourteen days following the date of this letter.

Sincerely,

ANTERO RESOURCES CORPORATION

By:

Name: Yvette K. Schultz
Title: Chief Compliance Officer, SVP – Legal, General Counsel and Corporate Secretary

AGREED AND ACCEPTED
this ____ day of ______, 20__ by:

[NAME]

ANNEX A

ANTERO RESOURCES CORPORATION

EXECUTIVE SEVERANCE PLAN

[See attached]

ANNEX B

NOTICE OF RESTRICTIVE COVENANTS, INCLUDING COVENANT NOT TO COMPETE

Antero Resources Corporation, a Delaware limited liability company (the "**Company**"), hereby gives notice to ________________ (**"Executive"**) that, in connection with the Antero Resources Corporation Executive Severance Plan dated effective as of September 17, 2025 (the "**Plan**"), Executive shall be required to enter into certain non-competition, non-solicitation, confidentiality and non-disclosure covenants (the **"Restrictive Covenants"**) contained in the Plan.

By signing below, Executive hereby acknowledges and agrees that:

1. A copy of the Plan and the Plan Participation Agreement has been provided to Executive, and are provided to Executive along with this notice;

2. Section 9(b) and (ii) of the Plan contain non-competition restrictions, and Sections 9(b)(iii) and (iv) of the Plan contain non-solicitation restrictions and Sections 8 and 10 of the Company Agreement contains confidentiality and non-disclosure restrictions.

3. The Plan contains covenants not to compete that could restrict Executive's options for subsequent employment following Executive's separation from the Company; and

4. If Executive accepts the terms of the Plan, Executive shall be doing so voluntarily (and Executive has not been subjected to force, threats or other intimidation in connection therewith), and with Executive's full understanding and acceptance of the Plan's terms (including the terms of the Restrictive Covenants).

Executive acknowledges that this notice has been provided to Executive at least 14 days before the earlier to occur of the effective date of the Restrictive Covenants. Executive further acknowledges and agrees that this notice is clear and conspicuous and that Executive fully understands the Restrictive Covenants Executive is being asked to enter.

ACKNOWLEDGED AND AGREED BY EXECUTIVE:

____
Signature

____
Name

____
Date

Exhibit 10.24

ANTERO RESOURCES CORPORATION
EXECUTIVE SEVERANCE PLAN
PARTICIPATION AGREEMENT

October 2, 2025

Paul M. Rady

Re: Participation Agreement – Antero Resources Corporation Executive Severance Plan

Dear Paul:

We are pleased to inform you that you have been designated as eligible to participate in the Antero Resources Corporation Executive Severance Plan (as it may be amended from time to time, the "Plan"). Your participation in the Plan is subject to the terms and conditions of the Plan, your execution and delivery of this agreement, which constitutes a Participation Agreement (as defined in the Plan), and your execution and delivery of the Notice of Restrictive Covenants. A copy of the Plan is attached hereto as Annex A and is incorporated herein and deemed to be part of this Participation Agreement for all purposes. A copy of the Notice of Restrictive Covenants is attached hereto as Annex B. Your participation in the Plan shall be effective 14 days following execution of this Participation Agreement and the Notice of Restrictive Covenants.

In signing below, you expressly agree to be bound by, and promise to abide by, the terms of Sections 7, 8, 9, and 10 of the Plan, which create certain restrictions with respect to confidentiality, non-solicitation, non-disparagement and post-termination cooperation. You further acknowledge that receipt of severance benefits following a Qualifying Termination under the Plan is contingent upon your execution of a general release of claims at the time of such Qualifying Termination and continued compliance with, to the extent applicable pursuant to the terms thereof, any restrictive covenants set forth in the Plan.

You acknowledge and agree that the Plan and this Participation Agreement supersede all prior severance benefit policies, plans and arrangements of the Company or any other member of the Resources Group (and supersedes all prior oral or written communications by the Company or any of other member of the Resources Group with respect to severance benefits), and all such prior policies, plans, arrangements and communications are hereby null and void and of no further force and effect with respect to your participation therein; *provided, however,* that the terms and provisions of the AR LTIP, the 2013 AR LTIP, the AM LTIP, and the award agreements under each such plan shall continue to govern the equity-based awards granted under such plans to an Eligible Executive following such Eligible Executive's termination of employment; *provided, further,* that the terms of the Chairman Emeritus Agreement (the "***Chairman Agreement***") entered into as of August 14, 2025 between you, the Company and Antero Midstream shall remain in full force and effect except for Section 3(e) of the Chairman Agreement, which is superseded by this Participation Agreement and the Plan.

Notwithstanding the definition of Qualifying Termination in the Plan, you will only be deemed to have incurred a Qualifying Termination in the event a Change in Control occurs during the term of the Chairman Agreement. In the event a Change in Control occurs during the term of the Chairman Agreement, the closing date of the transaction that constitutes a Change in Control shall be deemed to be the date of your Qualifying Termination (irrespective of whether your employment continues or is terminated) and the Company shall pay you, or cause you to be paid, $10,139,663.85 on or after the 14th day following the Release Consideration Period, but in no event later than 75 days following the closing date of the Change in Control. This payment represents the aggregate value of the cash payments you would have received pursuant to Section 5(a)(i), Section 5(a)(ii), and Section 5(a)(iii) of the Plan if you had experienced a Qualifying Termination on August 13, 2025 and the Plan was in place as of that date. You shall also be eligible to receive the benefits and payments described in Section 5(a)(iv) of the Plan; *provided, however*, that your COBRA Continuation Period shall commence on the first day of the first calendar month following the earliest to occur of (i) the end of the term of the Chairman Agreement, and (ii) the date of your loss of coverage under the Company's health plan, in each case only following a Change in Control. For the avoidance of doubt, you shall not be eligible to receive any payments or benefits pursuant to the Plan if a Change in Control does not occur during the term of the Chairman Agreement.

You further acknowledge and agree that (i) you have fully read, understand and voluntarily enter into this Participation Agreement and (ii) you have had a sufficient opportunity to consult with your personal tax, financial planning advisor and attorney about the tax, financial and legal consequences of your participation in the Plan before signing this Participation Agreement.

Unless otherwise defined herein, capitalized terms used in this Participation Agreement shall have the meanings set forth in the Plan. This Participation Agreement may be executed in separate counterparts, each of which shall be deemed an original, but all of which taken together shall constitute one and the same instrument. To the extent there is any conflict between the Plan and this Participation Agreement, the terms of this Participation Agreement shall control.

Please execute this Participation Agreement in the space provided below and send a fully executed copy to Yvette K. Schultz no later than fourteen days following the date of this letter.

Sincerely,

ANTERO RESOURCES CORPORATION

By: /s/ Yvette K. Schultz
Name: Yvette K. Schultz
Title: Chief Compliance Officer, SVP – Legal, General Counsel and Corporate Secretary

AGREED AND ACCEPTED
this 2nd day of October, 2025 by:

/s/ Paul M. Rady

PAUL M. RADY

ANNEX A

ANTERO RESOURCES CORPORATION

EXECUTIVE SEVERANCE PLAN

[See attached]

ANNEX B

NOTICE OF RESTRICTIVE COVENANTS, INCLUDING COVENANT NOT TO COMPETE

Antero Resources Corporation, a Delaware limited liability company (the "**Company**"), hereby gives notice to Paul M. Rady (**"Executive"**) that, in connection with the Antero Resources Corporation Executive Severance Plan dated effective as of September 17, 2025 (the "**Plan**"), Executive shall be required to enter into certain non-competition, non-solicitation, confidentiality and non-disclosure covenants (the **"Restrictive Covenants"**) contained in the Plan.

By signing below, Executive hereby acknowledges and agrees that:

1. A copy of the Plan and the Plan Participation Agreement has been provided to Executive, and are provided to Executive along with this notice;

2. Section 9(b) and (ii) of the Plan contain non-competition restrictions, and Sections 9(b)(iii) and (iv) of the Plan contain non-solicitation restrictions and Sections 8 and 10 of the Company Agreement contains confidentiality and non-disclosure restrictions.

3. The Plan contains covenants not to compete that could restrict Executive's options for subsequent employment following Executive's separation from the Company; and

4. If Executive accepts the terms of the Plan, Executive shall be doing so voluntarily (and Executive has not been subjected to force, threats or other intimidation in connection therewith), and with Executive's full understanding and acceptance of the Plan's terms (including the terms of the Restrictive Covenants).

Executive acknowledges that this notice has been provided to Executive at least 14 days before the earlier to occur of the effective date of the Restrictive Covenants. Executive further acknowledges and agrees that this notice is clear and conspicuous and that Executive fully understands the Restrictive Covenants Executive is being asked to enter.

ACKNOWLEDGED AND AGREED BY EXECUTIVE:

____
Signature

____
Name

____
Date

Exhibit 10.29

Antero Midstream Partners LP
1615 Wynkoop Street
Denver, Colorado 80202

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202

Re: Letter Agreement Regarding Membership Interest Purchase Agreement

This Letter Agreement (the "Letter Agreement") amends and restates the letter agreement, dated December 5, 2025, between Antero Midstream Partners LP ("AMLP") and Antero Resources Corporation ("Antero Resources"), and is effective as of such date. Reference is made to that certain Membership Interest Purchase Agreement, dated as of December 5, 2025, by and among HG Energy II LLC, HG Energy II Production Holdings, LLC (together with its subsidiaries, "HG Production"), HG Energy II Midstream Holdings, LLC (together with its subsidiaries, "HG Midstream"), Antero Resources Corporation ("Antero Resources") and Antero Midstream Partners LP ("AMLP") (as may be amended from time to time, the "Purchase Agreement"). Pursuant to the Purchase Agreement, (i) Antero Resources agreed to acquire all of the issued and outstanding equity interests of HG Production and (ii) AMLP agreed to acquire all of the issued and outstanding equity interests of HG Midstream. Antero intends to, pursuant to Section 11.6 of the Purchase Agreement, elect to treat part or all its acquisition of the Oil & Gas Assets owned by HG II Production or its direct or indirect subsidiaries (excluding, for the avoidance of doubt, the AM Assets (as defined below)) (the "Assigned Assets") via its acquisition of the HG II Production Interests, as an Exchange, and intends to assign all or a part of its rights under the Purchase Agreement with respect to the Assigned Assets to an exchange accommodation titleholder to effect such Exchange. Capitalized terms used but not defined in this Letter Agreement shall have the meanings ascribed to such terms in the Purchase Agreement. Antero Resources and AMLP are sometimes collectively referred to in this Letter Agreement as "Parties" and individually as a "Party".

In connection with the entry into the Purchase Agreement, the buyer-side representations and warranties insurance policies described on Schedule A attached hereto (collectively, the "Policy") were obtained with Antero Resources as the named insured thereunder and AMLP as the additional insured thereunder. This Letter Agreement sets forth the agreement of the Parties with respect to certain rights and obligations of the Parties under the Policy and the Purchase Agreement and certain other matters.

1. **Purchase Agreement**

(a) Purchase Price. Each Party agrees, at the Closing, upon the terms and conditions set forth in the Purchase Agreement and this Letter Agreement, to pay such Party's Pro Rata Share of the Base Purchase Price.

(b) Adjustments to Purchase Price. Each Party acknowledges that the Purchase Agreement provides certain (i) adjustments to the Base Purchase Price made at Closing pursuant to Section 2.3 of the Purchase Agreement and (ii) adjustments to the Purchase Price made post-Closing pursuant to Section 2.7 of the Purchase Agreement. While the Purchase Agreement specifies certain adjustments to the Base Purchase Price and Purchase Price will be made based on such Party's Pro Rata Share, each Party agrees that certain adjustments should be allocated in the following manner:

(i) Adjustments pursuant to the following sections of the Purchase Agreement shall be allocated to Antero Resources or AMLP based on the relative cost, liability, obligation, fault, damage, payment or benefit to HG Production or HG Midstream, respectively:

1. Section 2.3(b)(i)(A-C) and (E-H);
2. Section 2.3(b)(ii)(A-G) and (I-M);
3. Section 2.3(c)(i)(A-E);
4. Section 2.3(c)(ii)(A); and
5. Section 2.3(d).

(ii) Adjustments pursuant to the following sections of the Purchase Agreement shall be allocated to Antero Resources or AMLP based on such Party's Pro Rata Share:

1. Section 2.3(b)(i)(D); and
2. Section 2.3(b)(ii)(H).

(c) Allocation of Other Items. Each Party agrees that certain costs and benefits should be allocated in the following manner:

(i) Cost and benefits under the following sections of the Purchase Agreement shall be allocated to Antero Resources or AMLP based on the relative cost, liability, obligation, fault, damage, payment or benefit to HG Production or HG Midstream, respectively:

1. Section 2.11(b)(x);
2. Section 5.1;
3. Articles VI – VIII;

4. Section 9.1(d); *provided*, that if fault (or relative fault) is not clearly attributable to one entity, allocation shall be subject to Section 1(c)(ii) of this Letter Agreement;

5. Section 9.9;

6. Section 9.2;

7. Section 9.13; and

8. Section 9.15.

(ii) Cost and benefits under the following sections of the Purchase Agreement shall be allocated to Antero Resources or AMLP based on such Party's Pro Rata Share:

1. Section 9.1(d) and (e);

2. Section 9.4;

3. Section 9.5;

4. Section 9.8;

5. Section 9.11; and

6. Section 9.12; *provided*, that filing fees actually paid by a Party shall be allocated to such Party.

(iii) Tax Matters. As between Antero Resources and AMLP:

1. Taxes of or relating to HG Production and its Subsidiaries shall be allocated to Antero Resources, and Taxes of or relating to HG Midstream and its Subsidiaries shall be allocated to AMLP; *provided* that Taxes of or relating to the AM Assets (as defined below) shall be allocated to AMLP and not Antero Resources.

2. Antero Resources and AMLP shall each be entitled to any and all Tax refunds and credits of Taxes allocated to it pursuant to Section 1.3(c)(iii)(1) hereof. If a Party or its Affiliate receives a refund of Taxes to which the other Party is entitled pursuant to this Section 1(c)(iii)(2), such recipient Party shall forward to the entitled Party the amount of such refund within thirty (30) days after such refund is received, net of any costs or expenses incurred by such recipient Party in procuring such refund.

3. Antero Resources shall be entitled to control, at its sole cost and expense, any audit or administrative or judicial proceeding with respect

to any Taxes or Tax Return (a "Tax Contest") with respect to Taxes allocated to it pursuant to Section 1(c)(iii), and AMLP shall be entitled to control, at its sole cost and expense, any Tax Contest with respect to Taxes allocated to it pursuant to Section 1(c)(iii).

(iv) In the event that all or any portion of the Deposit is forfeited pursuant to the terms of the Purchase Agreement, responsibility for such forfeited Deposit shall be allocated to each Party based upon the relative fault of such Party in the matters giving rise to such forfeiture.

(v) Buyer costs under Section 9.16 and 9.17 of the Purchase Agreement shall be allocated to the Party making the request giving rise to such cost.

(vi) In the event that Buyer forfeits all or any portion of the Deposit in accordance with Section 13.3(a) of the Purchase Agreement, liability for the forfeited deposit shall be allocated to Antero Resources and AMLP based on each Party's relative fault. In the event that Buyer recovers actual damages and out-of-pocket expenses pursuant to Section 13.3(b) of the Purchase Agreement, the recovery shall be allocated to Antero Resources and AMLP based on each Party's actual damages and out-of-pocket expenses.

(d) In the event that the Parties believe that a cost, liability, obligation, fault, damage or benefit allocated to a Party under this Section 1 should be allocated to the other Party, such cost, liability, obligation, fault, damage or benefit may be allocated to such other Party upon the mutual agreement of the Parties. Subject to the preceding sentence, if at any time a Party believes that (i) such Party has incurred a cost, liability, obligation, fault or damage that should have been allocated to the other Party pursuant to the terms of this Letter Agreement or (ii) the other Party has received a payment or benefit that should have been allocated to such Party, such Party (the "Noticing Party") shall deliver written notice to the other Party (the "Noticed Party"), which notice shall set forth in reasonable detail the Noticing Party's good faith determination of (i) any cost, liability, obligation, fault or damage actually incurred by the Noticing Party that should have been allocated to the Noticed Party or (ii) any payment or benefit actually received by the Noticed Party that should have been allocated to the Noticing Party, in each case along with reasonable supporting detail.

Upon receipt by the receiving Party of a notice pursuant to this Section 1(d), the Parties, acting in good faith, shall attempt to agree on the extent to which any cost, expense, payment or benefit was improperly incurred or received. If the Parties agree on the amount that was improperly incurred by the Noticing Party or improperly received by the Noticed Party, the Noticed Party shall, within 10 days after such agreement, pay the agreed amount to the Noticing Party.

If the Parties are unable to agree on the amount that was improperly incurred or received within 20 days after receipt of notice of a notice pursuant to this Section 1(d), the dispute between the Parties with respect to such allegedly improperly incurred or received amount shall be exclusively and finally resolved by final and binding confidential arbitration pursuant to this Section 1(d). There shall be a single arbitrator ("Arbitrator"), who shall be the Houston, Texas office of Deloitte (or such other independent, nationally recognized accounting firm the Parties mutually select), provided that such person neither presently is, nor in the past five years has been, retained to represent either Party in a matter material to such Party (other than with respect resolving disputes under this Letter Agreement), and who shall not, under applicable standards of professional conduct then prevailing, have a conflict of interest in representing either Party in an action to determine such Party's rights under this Letter Agreement. The arbitration proceeding shall be held in Houston, Texas and shall commence no later than 90 days following appointment of the Arbitrator. The Arbitrator's determination shall be made within 30 days after submission of the matters in dispute and shall be final and binding upon both Parties, without right of appeal. In making its determination, the Arbitrator shall be bound by the rules set forth in this Section 1(d) and the Purchase Agreement and, subject to the foregoing, may consider such other matters as in the opinion of the Arbitrator are necessary or helpful to make a proper determination. The Arbitrator's determination shall be limited to determining the amount that was alleged to be improperly incurred or received by a Party. Each Party shall each bear its own legal fees and other costs of presenting its case. The Arbitrator shall also clearly state which Party's positions in the aggregate that the Arbitrator found more persuasive in its decision making process, and the other Party shall bear 100% of the costs and expenses of the Arbitrator.

(e) In order to better give effect to the intent of the Parties that (i) Antero Resources (or its assignee) acquire the upstream business of HG Energy II LLC and that (ii) AMLP (directly or indirectly) acquire the midstream business and water business of HG Energy II LLC, the Parties acknowledge that certain assets owned by HG Production or its direct or indirect subsidiaries relating to the midstream and/or water businesses (the "AM Assets") will be conveyed by HG Production or its subsidiaries to AMLP or its direct or indirect subsidiaries immediately after the Closing (and which conveyance has been taken into account in the Party's respective Pro Rata Shares of the Purchase Price) (such assets, the "Certain Conveyed Assets"). Accordingly, any reference herein to the benefits to or costs of a Party, HG Production, HG Midstream or similar references, and any rights of AMLP pursuant to the Policy, shall in each case take into account the fact that AMLP or its subsidiary has acquired the assets the subject of the conveyances described in this Section 1(e).

2. Insurance Policy

(a) Maintenance of Policy. Each Party agrees to take such actions as are reasonably necessary to keep the Policy in full force and effect until the 84-month anniversary of the Closing Date (or such earlier or later time as the Parties shall mutually agree), including to pay (or causing to be paid) premium and other payments as described in Section 2(b) hereof. Antero Resources shall promptly provide to AMLP any notice Antero Resources receives as the named insured regarding the Policy, including but not limited to any notice of termination, cancellation, non-payment of premium, assignment of or request to assign the Policy or any portion thereof to another insurance company, request to modify or amend any terms of the Policy, or revocation of authority provided to any underwriting agent or claims adjuster by the insurers issuing the Policy. The Parties agree to reasonably cooperate with respect to any such notice, and Antero Resources shall use commercially reasonable efforts to ensure that AMLP's rights as additional insured are not adversely affected in connection with any such notice. To the extent either Party intends to assign its rights to receive proceeds payable under the Policy to any lender providing financing in connection with the transactions contemplated by the Purchase Agreement pursuant to Section XII.F of the primary layer of the Policy and/or name any such lender a loss payee under the Policy, the Parties agree to use commercially reasonable efforts to cooperate to effectuate such assignment and/or the naming of such lender as a loss payee up to the Pro Rata Share of the Policy limit applicable to such Party.

(b) Premiums. In accordance with Section 9.8 of the Purchase Agreement, Antero Resources and AMLP shall each pay (or cause to be paid) its Pro Rata Share of all costs of the Policy in a reasonably prompt manner as such costs come due, including any fees, costs, premiums, underwriting fees, Taxes, and commissions. For avoidance of doubt, any costs associated with the retention or deductible under the Policy shall be borne as set forth in Section 2(e) hereof.

(c) Claims and Policy Proceeds.

(i) Notice of Intent to Make Claim; Joint Claims; Cooperation. At least 10 days prior to making a claim under the Policy, a Party shall notify the other Party of its intent to do so (such notice, a "Claim Notice"). Within 5 days after receiving a Claim Notice, the Party receiving such Claim Notice shall notify the other Party if it intends to make a joint claim under the Policy (such notice, a "Joint Claim Notice"), in which case the Parties will reasonably coordinate to submit a joint claim under the Policy (a "Joint Claim"). Regardless of whether the Parties submit a Joint Claim, the Parties agree to use commercially reasonable efforts to cooperate in connection with either Party's pursuit of any claim under the Policy, including providing any requested documents and making available representatives of either Party to assist with such claim. With respect to pursuit of any claim, the Parties agree to maintain confidentiality of their communications and documents exchanged and preserve all applicable privileges between them to the maximum extent of the law.

(ii) Policy Proceeds. Except as otherwise set forth in this Letter Agreement, and subject to Policy limits and retention requirements, Antero Resources shall be entitled to any Policy proceeds for claims relating to HG Production (other than the Certain Conveyed Assets) and AMLP shall be entitled to any Policy proceeds for claims relating to HG Midstream (and the Certain Conveyed Assets). It is acknowledged and agreed that Antero Resources, as the named insured under the Policy, has the right pursuant to Section VII.D of the primary layer of the Policy to receive payment of any Policy proceeds or direct payment to another person or entity. Antero Resources hereby agrees to distribute any Policy proceeds it receives or direct payment of any Policy proceeds in accordance with this Section 2(c) to ensure that Policy proceeds for claims relating to HG Production (other than the Certain Conveyed Assets) are received by Antero Resources and Policy proceeds for claims relating to HG Midstream (and the Certain Conveyed Assets) are received by AMLP. To the extent a claim relates to both HG Production (other than the Certain Conveyed Assets), one the one hand, and HG Midstream and the Certain Conveyed Assets, on the other hand, Policy proceeds for such claim shall be allocated to Antero Resources and AMLP in proportion to the relative damage sustained by each Party as a result of the matter giving rise to such claim. To the extent the relative damage sustained by each Party as a result of the matter giving rise to such claim is indeterminable, each Party shall be allocated its Pro Rata Share of any Policy proceeds for such claim. If the Parties, acting in good faith, are unable to agree how to allocate Policy proceeds for a claim, the Parties will use the procedures set forth below to determine how payment of such claim will be allocated.

(iii) Dispute Resolution Procedure for Policy Proceeds. Upon receipt of notice that any insurers issuing the Policy intend to pay proceeds of the Policy for any claim, the Parties, acting in good faith, shall attempt to agree on how such Policy proceeds will be allocated between the Parties. If the Parties are unable to agree on the allocation of any such Policy proceeds within 20 days after receipt of notice that such proceeds will be paid by any insurers, the dispute between the Parties with respect to allocation of such proceeds shall be exclusively and finally resolved by final and binding confidential arbitration pursuant to this Section 2(c). There shall be a single arbitrator ("Arbitrator"), who shall be an attorney with at least 10 years' experience in the upstream and midstream oil and gas industry and who neither presently is, nor in the past five years has been, retained to represent either Party in a matter material to such Party (other than with respect resolving disputes under this Letter Agreement), and who shall not, under applicable standards of professional conduct then prevailing, have a conflict of interest in representing either Party in an action to determine such Party's rights under this Letter Agreement. The Parties shall attempt to agree on an arbitrator that meets such qualifications in good faith. If the Parties cannot agree on an arbitrator within 14 days, the Parties shall apply to the Denver office of the American Arbitration Association for selection of the arbitrator. The arbitration proceeding shall be held in Denver, Colorado and shall commence no later than 90 days following appointment of the Arbitrator. The Arbitrator's determination shall be made within 30 days after submission of the matters in dispute and shall be final and binding upon both Parties, without right of appeal. In making his or her determination, the Arbitrator shall be bound by the rules set forth in this Section 2.3(c) and, subject to the foregoing, may consider such other matters as in the opinion of the Arbitrator are necessary or helpful to make a proper determination. The Arbitrator, however, may not allocate to a Party an amount, if paid out under the Policy, that would result in the aggregate amount of payments to such Party under the Policy to exceed such

Party's Pro Rata Share of the maximum Policy limit. The Arbitrator's determination shall be limited to determining how to allocate Policy proceeds on a claim. Each Party shall each bear its own legal fees and other costs of presenting its case. The Arbitrator shall also clearly state which Party's positions in the aggregate that the Arbitrator found more persuasive in its decision making process, and the other Party shall bear 100% of the costs and expenses of the Arbitrator.

(d) Limits. Without the consent of the other Party, no Party shall be entitled to be allocated Policy proceeds in an amount which would result in such Party having received aggregate claims payments in excess of such Party's Pro Rata Share of the maximum Policy limit.

(e) Retention. If at the time payment of any Policy proceeds is made the portion of the aggregate retention borne under the Policy by a Party exceeds such Party's Pro Rata Share of the maximum amount of retention required by the Policy, the Party receiving payment on such claim (the "Receiving Party") shall be required to pay (such payment, a "True-up Payment") to the other Party (the "Other Party") an amount in cash equal to (i) the retention amount borne by the Other Party *minus* (ii) the Other Party's Pro Rata Share of the maximum amount of retention required by the Policy; *provided*, the amount of cash to be paid as a True-up Payment shall not exceed the amount of cash received by the Receiving Party in respect of such claim.

(f) Assignment of Policy. Without the prior written consent of the other Party, a Party shall not assign the Policy (or any rights or obligations thereunder) to any person unless such Party's rights and obligations under this Section 2 are also assigned to such person in compliance with Section 5 hereof.

3. Service Agreement Amendments

Each Party agrees to use commercially reasonable efforts to cause (i) that certain Second Amendment and Restated Gathering and Compression Agreement, dated December 8, 2019, by and between Antero Resources and Antero Midstream LLC and (ii) that certain First Amended and Restated Water Services Agreement, dated effective as of September 24, 2015, by and between Antero Resources, Antero Water LLC and Antero Treatment LLC to be amended with an effective date of the Effective Time to, among other things, provide for on-pad compression with respect to certain wells and a transition period before certain water services will be provided under the agreements with respect to certain assets, on terms approved by the Conflicts Committees of the Boards of Directors or Antero Resources and Antero Midstream Corporation.

4. Notices

Except with respect to any notices contemplated in connection with the Exchange, all notices, requests, or consents provided for or permitted to be given under this Letter Agreement must be in writing and must be given either by depositing that writing in the United States mail, addressed to the recipient, postage paid, and registered or certified with return receipt requested or by delivering that writing to the recipient in person, by courier, or by electronic transmission; and a notice, request, or consent given under this Letter Agreement is effective on receipt by the person to receive it. All notices, requests, and consents to be sent to a Party hereto must be sent to or made at the following addresses (or such other address as that Party may specify by notice to the other Parties):

If to AMLP:

Antero Midstream Partners LP
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Justin J. Agnew (**********)
Yvette K. Schultz (generalcounsel@anteroresources.com)

If to Antero Resources:

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Brendan E. Krueger (**********)
Yvette K. Schultz (generalcounsel@anteroresources.com)

5. Assignment

This Letter Agreement may not be assigned by either Party without the prior written consent of the other Party; *provided* that Antero Resources may assign all or a part of this Letter Agreement to an exchange accommodation titleholder, and such exchange accommodation titleholder may assign this Letter Agreement to Antero Resources or one of its affiliates, in each case including, for the avoidance of doubt, its rights and obligations under Section 2 of this Letter Agreement.

6. Governing Law; Consent to Jurisdiction; Waiver of Jury Trial

(a) Governing Law. THIS LETTER AGREEMENT AND ALL CLAIMS OR CAUSES OF ACTION (WHETHER IN CONTRACT, TORT OR STATUTE) THAT MAY BE BASED UPON, ARISE OUT OF OR RELATE TO THIS LETTER AGREEMENT, OR THE NEGOTIATION, EXECUTION OR PERFORMANCE OF THIS LETTER AGREEMENT SHALL BE GOVERNED BY, AND ENFORCED IN ACCORDANCE WITH THE INTERNAL LAWS OF THE STATE OF TEXAS, INCLUDING STATUTES OF LIMITATIONS, WITHOUT REGARD TO ANY BORROWING STATUTE THAT WOULD RESULT IN THE APPLICATION OF THE STATUTE OF LIMITATIONS OF ANY OTHER JURISDICTION; P*ROVIDED*, *HOWEVER*, THAT ANY MATTERS RELATED TO REAL PROPERTY SHALL BE GOVERNED BY THE LAWS OF THE STATE WHERE SUCH REAL PROPERTY IS LOCATED TO THE EXTENT MANDATORILY REQUIRED.

(b) Consent to Jurisdiction and Service of Process; Appointment of Agent for Service of Process. EXCEPT AS OTHERWISE EXPRESSLY PROVIDED IN THIS LETTER AGREEMENT, EACH PARTY TO THIS LETTER AGREEMENT HEREBY CONSENTS TO THE EXCLUSIVE JURISDICTION OF THE STATE COURTS (INCLUDING THE ELEVENTH DIVISION OF THE TEXAS BUSINESS COURT) AND TEXAS FEDERAL COURT OF THE UNITED STATES OF AMERICA SITTING IN HOUSTON, TEXAS, AND IRREVOCABLY AGREES THAT ALL ACTIONS OR PROCEEDINGS SEEKING TO ENFORCE ANY PROVISION OF, OR BASED ON ANY MATTER ARISING OUT OF OR IN CONNECTION WITH, THIS LETTER AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY (WHETHER SUCH ACTIONS OR PROCEEDINGS ARE BASED IN STATUTE, TORT, CONTRACT OR OTHERWISE), SHALL BE LITIGATED IN SUCH COURTS. EACH PARTY HERETO (I) CONSENTS TO SUBMIT ITSELF TO THE PERSONAL JURISDICTION OF SUCH COURTS FOR SUCH ACTIONS OR PROCEEDINGS, (II) WAIVES ANY OBJECTION OR CHALLENGE THAT IT MAY HAVE TO THE PERSONAL JURISDICTION OF SUCH COURTS, AND (III) AGREES THAT IT WILL NOT BRING ANY SUCH ACTION OR PROCEEDING IN ANY COURT OTHER THAN SUCH COURTS. EACH PARTY HERETO ACCEPTS FOR ITSELF AND IN CONNECTION WITH ITS PROPERTIES, GENERALLY AND UNCONDITIONALLY, THE EXCLUSIVE AND IRREVOCABLE JURISDICTION AND VENUE OF THE AFORESAID COURTS AND WAIVES ANY DEFENSE OF FORUM NON CONVENIENS, AND IRREVOCABLY AGREES TO BE BOUND BY ANY NON-APPEALABLE JUDGMENT RENDERED THEREBY IN CONNECTION WITH SUCH ACTIONS OR PROCEEDINGS. A COPY OF ANY SERVICE OF PROCESS SERVED UPON THE PARTIES HERETO SHALL BE MAILED BY REGISTERED MAIL TO THE RESPECTIVE PARTY EXCEPT THAT, UNLESS OTHERWISE PROVIDED BY APPLICABLE LAW, ANY FAILURE TO MAIL SUCH COPY SHALL NOT AFFECT THE VALIDITY OF SERVICE OF PROCESS. IF ANY AGENT APPOINTED BY A PARTY HERETO REFUSES TO ACCEPT SERVICE, EACH PARTY HERETO AGREES THAT SERVICE UPON THE APPROPRIATE PARTY BY REGISTERED MAIL SHALL CONSTITUTE SUFFICIENT SERVICE. NOTHING HEREIN SHALL AFFECT THE RIGHT OF A PARTY HERETO TO SERVE PROCESS IN ANY OTHER MANNER PERMITTED BY LAW.

(c) Waiver of Jury Trial. EACH PARTY HEREBY IRREVOCABLY WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY ACTION ARISING OUT OF OR RELATING TO THIS LETTER AGREEMENT OR ANY OF THE TRANSACTIONS CONTEMPLATED BY THIS LETTER AGREEMENT. EACH PARTY ACKNOWLEDGES, AGREES AND CERTIFIES THAT (I) NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD, IN THE EVENT OF LITIGATION, SEEK TO PREVENT OR DELAY ENFORCEMENT OF SUCH WAIVER; (II) IT UNDERSTANDS AND HAS CONSIDERED THE IMPLICATIONS OF SUCH WAIVER; (III) IT MAKES SUCH WAIVER VOLUNTARILY; AND (IV) IT HAS BEEN INDUCED TO

ENTER INTO THIS LETTER AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 6(c).

7. Amendment

All waivers, modifications, amendments and changes to this Letter Agreement shall be in writing and executed by the authorized representatives of the Parties.

8. Binding Effect

This Letter Agreement shall bind and inure to the benefit of the Parties and their respective heirs, legal representatives, executors, successors and permitted assigns.

9. Severability

If any term, covenant or condition of this Letter Agreement or the application thereof to any person or circumstance shall, to any extent, be held invalid or unenforceable, the remainder of this Letter Agreement, or the application of such term, covenant or condition to persons or circumstances other than those as to which it is held invalid or unenforceable, shall not be affected thereby and each term, covenant or condition of this Letter Agreement shall be valid and enforceable to the fullest extent permitted by law.

10. Entire Agreement

This is the entire agreement between the Parties with respect to the matters covered by this Letter Agreement. It supersedes any and all other prior agreements, understanding, negotiations and discussions, oral or written, with respect to these matters.

11. Counterparts

This Letter Agreement may be executed in multiple counterparts, all of which, taken together, shall constitute an original document.

[Signature Page Follows]

Kindly acknowledge your agreement with the foregoing by signing this letter in the space provided below.

Sincerely,

ANTERO MIDSTREAM PARTNERS LP

By: Antero Midstream Partners GP LLC,
its general partner

By: /s/ Justin Agnew____________________

Name: Justin Agnew
Title: Chief Financial Officer and Vice President – Finance

ANTERO RESOURCES CORPORATION

By: /s/ Brendan Krueger________________

Name: Brendan Krueger
Title: Chief Financial Officer, Senior Vice President – Finance and Treasurer

Exhibit 21.1

SUBSIDIARIES OF ANTERO RESOURCES CORPORATION

Name of Subsidiary	Jurisdiction of Organization
Appalachian Real Estate LLC	Delaware
Antero Minerals LLC	Delaware
Antero Subsidiary Holdings LLC	Delaware
Martica Holdings LLC	Delaware
Martius Properties LLC	Delaware
Monroe Pipeline LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statement (No. 333-292670) on Form S-3 and registration statements (Nos. 333-281151, 333-239773 and 333-191693) on Form S-8 of our report dated February 11, 2026, with respect to the consolidated financial statements of Antero Resources Corporation and subsidiaries and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Denver, Colorado
February 11, 2026

Exhibit 23.2

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 11, 2026

Board of Directors of Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202

Ladies and Gentlemen:

We hereby consent to the incorporation by reference in (i) the Registration Statement on Form S-3 (File No. 333-292670), (ii) the Registration Statement on Form S-8 (File No. 333-281151), (iii) the Registration Statement on Form S-8 (File No. 333-239773) and (iv) the Registration Statement on Form S-8 (File No. 333-191693) of Antero Resources Corporation (the “Company”) of information taken from our report of third party dated January 13, 2026, with respect to the Company’s estimated proved reserves as of December 31, 2025.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Michael N. Kennedy, Chief Executive Officer and President of Antero Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2025 of Antero Resources Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2026

/s/ Michael N. Kennedy
Michael N. Kennedy
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Brendan E. Krueger, Chief Financial Officer, Senior Vice President – Finance and Treasurer of Antero Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2025 of Antero Resources Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 11, 2026

/s/ Brendan E. Krueger

Brendan E. Krueger
Chief Financial Officer, Senior Vice President – Finance and Treasurer

Exhibit 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with this Annual Report on Form 10-K of Antero Resources Corporation for the year ended December 31, 2025, I, Michael N. Kennedy, Chief Executive Officer and President of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2025 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2025 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: February 11, 2026

/s/ Michael N. Kennedy

Michael N. Kennedy
Chief Executive Officer and President

Exhibit 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF ANTERO RESOURCES CORPORATION
PURSUANT TO 18 U.S.C. SECTION 1350

In connection with this Annual Report on Form 10-K of Antero Resources Corporation for the year ended December 31, 2025, I, Brendan E. Krueger, Chief Financial Officer, Senior Vice President – Finance and Treasurer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2025 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2025 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: February 11, 2026

/s/ Brendan E. Krueger

Brendan E. Krueger
Chief Financial Officer, Senior Vice President – Finance and Treasurer

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

January 13, 2026

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2025, of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves and present worth of certain properties in which Antero Resources Corporation (Antero) has represented it holds an interest. This evaluation was completed on January 13, 2026. The properties evaluated consist of working and royalty interests located in Ohio and West Virginia. Antero has represented that these properties account for 99.91 percent on a million cubic feet net equivalent basis of Antero's net proved reserves as of December 31, 2025, and that the net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). It is our opinion that the procedures and methodologies employed by Antero for the preparation of its proved reserves estimates as of December 31, 2025, comply with the current requirements of the SEC. We have reviewed information provided by Antero that it represents to be Antero's estimates of the net reserves, as of December 31, 2025, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Antero.

Reserves estimates included herein are expressed as net reserves as represented by Antero. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2025. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Antero after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Antero to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Antero, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a discount rate of 10 percent compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and present worth should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Antero and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Antero with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plan provided by Antero, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves were based on opportunities identified in the plan of development provided by Antero.

Antero has represented that its senior management is committed to the development plan provided by Antero and that Antero has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Antero from wells drilled through December 31, 2025, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of daily and monthly production data available through December 2025. Cumulative production, as of December 31, 2025, was deducted from the estimated gross ultimate recovery to estimate gross reserves.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the pressure base of the state in which the quantities are located. Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Antero, liquid reserves estimated herein were converted to gas equivalent using an energy equivalent factor of 1 barrel of liquids per 6,000 cubic feet of gas equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Antero. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Antero has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first day-of-the-month price for each month within the 12 month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Antero supplied differentials to the NYMEX Light Sweet Crude Oil reference price of $65.34 per barrel and the prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $52.34 per barrel of oil and condensate and $25.19 per barrel of NGL.

Gas Prices

Antero has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Antero supplied differentials to a NYMEX reference price of $3.39 per million Btu ($/MMBtu) and the prices were held constant thereafter. Btu factors provided by Antero were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $3.42 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for each state in which the reserves are located. Ad valorem taxes were calculated using rates provided by Antero based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Antero and based on existing economic conditions, were held constant for the lives of the properties. Future capital expenditures were estimated using 2025 values, provided by Antero, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Antero for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

DeGolyer and MacNaughton has performed an independent evaluation of the extent of the estimated net proved oil, condensate, NGL, and gas reserves of certain properties in which Antero has represented it holds an interest. Antero has represented that its estimated net proved reserves and present worth at 10 percent attributable to the evaluated properties were based on the definitions of proved reserves of the SEC. Antero's estimates of the net proved reserves and present worth, as of December 31, 2025, attributable to these properties, which represent 99.91 percent of Antero's total proved reserves on a net equivalent basis, are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), millions of cubic feet equivalent (MMcfe), and thousands of dollars (M$):

	Estimated by Antero Net Proved Reserves and Present Worth at 10 Percent as of December 31, 2025				
Proved Reserves	**Oil and Condensate (Mbbl)**	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Gas Equivalent (MMcfe)**	**Present Worth at 10 Percent (M$)**
Proved Developed					
Evaluated by DeGolyer and MacNaughton	12,374	1,001,975	8,374,778	14,460,867	8,244,103
Not Evaluated by DeGolyer and MacNaughton	0	655	13,398	17,328	14,967
Total Proved Developed	12,374	1,002,630	8,388,176	14,478,195	8,259,070
Proved Undeveloped					
Evaluated by DeGolyer and MacNaughton	10,135	204,742	3,381,558	4,670,825	1,419,697
Not Evaluated by DeGolyer and MacNaughton	0	0	0	0	0
Total Proved	**22,509**	**1,207,372**	**11,769,734**	**19,149,020**	**9,678,767**

Notes:
1. Liquid reserves estimated herein were converted to gas equivalent using an energy equivalent factor of 1 barrel of liquids per 6,000 cubic feet of gas equivalent.
2. Future income taxes have not been taken into account in the preparation of the estimates of present worth.

In comparing the detailed net proved reserves estimates prepared by DeGolyer and MacNaughton and by Antero of the properties evaluated, differences have been found, both positive and negative, resulting in an aggregate difference of 2.1 percent for the evaluated properties when compared on the basis of net gas equivalent. It is DeGolyer and MacNaughton's opinion that there is no material difference between the net proved reserves estimates prepared by Antero and those prepared by DeGolyer and MacNaughton for those properties DeGolyer and MacNaughton evaluated. In comparing the detailed present worth at 10 percent estimates prepared by DeGolyer and MacNaughton and by Antero of the properties evaluated, differences have been found, both positive and negative, resulting in an aggregate difference of less than 1 percent for the evaluated properties when compared on the basis of present worth at 10 percent. It is DeGolyer and MacNaughton's opinion that there is no material difference between the present worth at 10 percent estimates prepared by Antero and those prepared by DeGolyer and MacNaughton for those properties we evaluated.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2025, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Antero. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Antero. DeGolyer and MacNaughton has used all data, assumptions, procedures, and methods that it considers necessary to prepare this report.

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Dilhan Ilk
Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Dilhan Ilk, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am an Executive Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Antero dated January 13, 2026, and that I, as Executive Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, 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; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 15 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Dilhan Ilk

Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton