Antero Resources

2020
ANNUAL REPORT

BUSINESS STRATEGY

- PRODUCT DIVERSITY AS A LEADING NATURAL GAS AND NGL PRODUCER
- MITIGATE COMMODITY PRICE RISK WITH HEDGES AND FIRM TRANSPORTATION
- DISCIPLINED FOCUS ON RETURNS
- MAINTAIN STRONG BALANCE SHEET AND FINANCIAL FLEXIBILITY
- LEADING SUSTAINABILITY AND ESG METRICS

DEAR FELLOW SHAREHOLDERS,

As we reflect back on 2020, we want to express our appreciation for the hard work and dedication of our talented employees through the significant challenges presented by the COVID-19 global pandemic. During these unprecedented times, Antero Resources' people delivered the low-emission hydrocarbons needed to produce and transport medical supplies and personal protective equipment and to heat and power our communities. Their skills and determination represent the true strength and competitive advantage of Antero Resources. As we look ahead, we are committed to the health and safety of our employees, to the West Virginia and Ohio communities where we operate, and to responsibly delivering the energy needed to drive a recovering global economy.

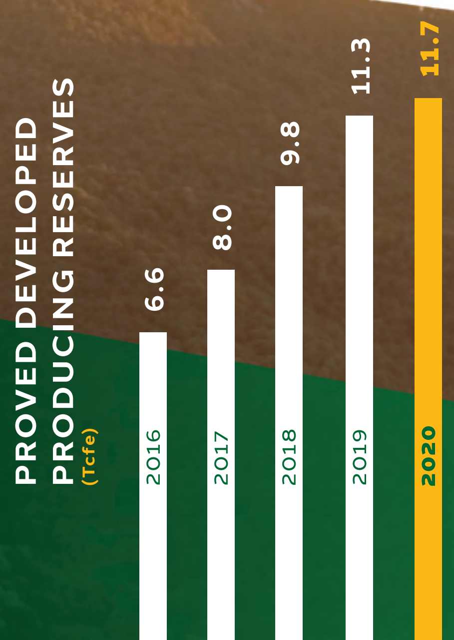
Antero's unique positioning, including our liquid-rich production mix, firm transportation portfolio, and hedge position, allowed us to continue developing our resource base through the commodity price downturn in 2020. Antero Resources averaged 3.6 Bcfe/d of net production in 2020, delivering 11% year-over-year net production growth. This production included 198 MBbl/d of NGLs and oil, or 33% of our total net production by volume. At year-end 2020, Antero Resources was the second largest NGL producer and the third largest natural gas producer in the U.S.

A STRONG BALANCE SHEET

We made tremendous strides in improving Antero Resources' financial strength in 2020. Since embarking on our asset sale program in late 2019, we have successfully raised $1.3 billion through a series of transactions. These included a Volumetric Production Payment (VPP), an overriding royalty transaction, and a drilling partnership. This high level of counterparty investment in a volatile environment was a strong endorsement of Antero Resources' assets and operations. These successful transactions allowed us to access the senior unsecured debt markets several times in 2020 and 2021, raising over $1.5 billion in proceeds and eliminating $2.3 billion of near-term maturities. Given these proactive steps, we successfully right-sized the balance sheet and re-balanced the debt maturity schedule. These transactions, combined with free cash flow, are expected to drive leverage under 2.0x in 2021.

COST REDUCTIONS

Operating momentum remained a core focus in 2020. We continued the cost reduction and efficiency initiative that began in 2019. These efforts are expected to lead to well-cost reductions of 35% in 2021, as compared to the beginning of the program. Reduced well costs are a primary component of the 20% reduction in capital expenditures in 2021, as compared to the prior year, while delivering flat production. This improved capital efficiency is expected to result in sustained free cash flow generation going forward, assuming current strip pricing. In 2021, we will remain steadfast in continuing to reduce our overall cost structure with a goal of continuing to be a peer leader in returns regardless of the commodity cycle.



PRODUCTION AVERAGED 3.6 BCFE/D IN 2020, DELIVERING 11% YEAR-OVER-YEAR GROWTH.

17.6 Tcfe
Net Proved Reserves

515,000
Net Acres

29%
AM Ownership

2,100+
Premium Core Drilling Locations

41 %
Liquids Revenue Contribution

3.6 Bcfe/d
Total Net Production

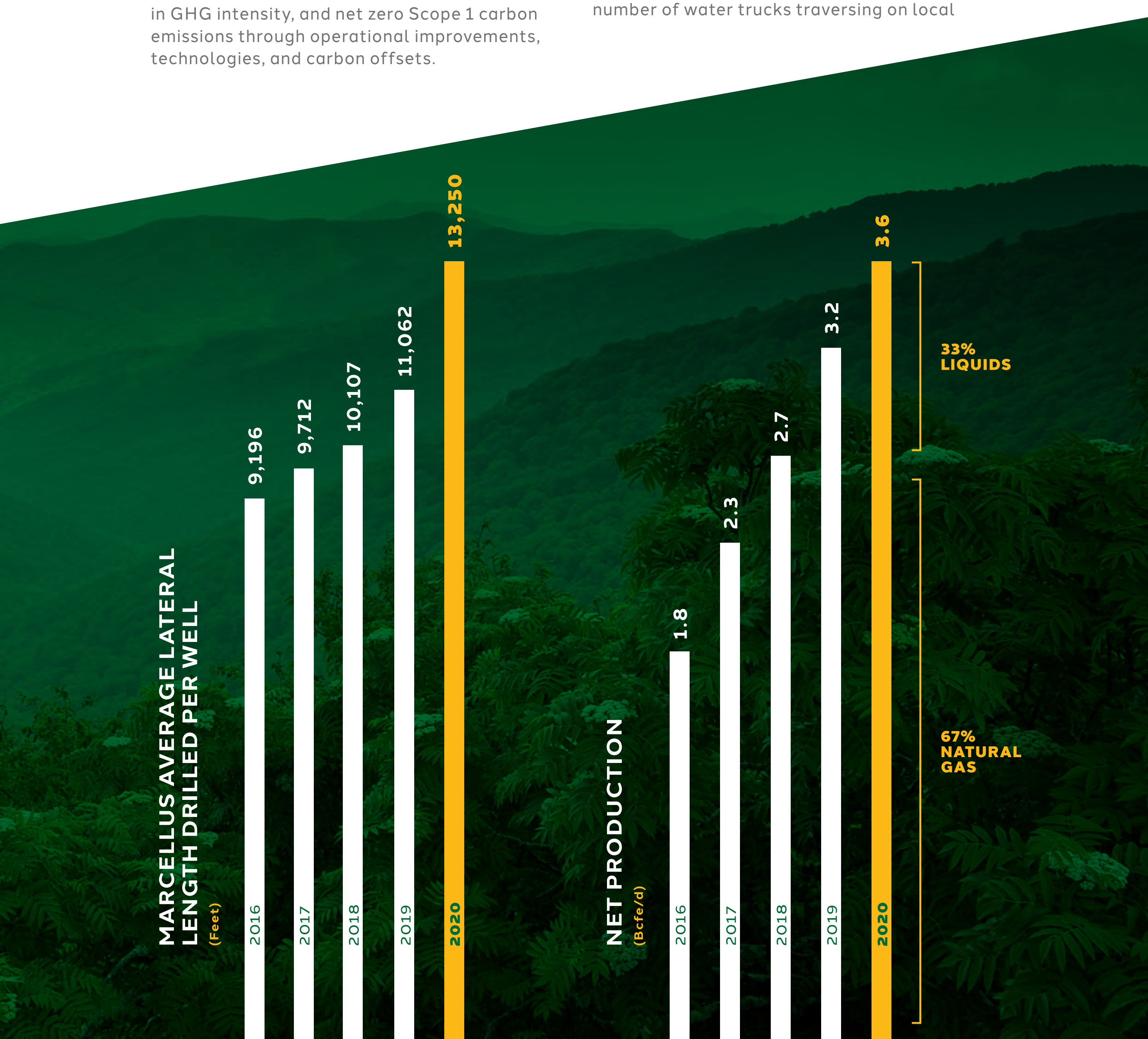
$0.27 Mcfe
Marcellus F&D Cost

186,000 Bbl/d
Natural Gas Liquids Production

CORPORATE SUSTAINABILITY

We made significant progress in Antero's environmental, social and governance (ESG) initiatives during 2020. In April, we established an Environment, Sustainability, and Social Governance Committee of the Board of Directors. This Committee provides guidance to management and the Board on matters relating to the identification, evaluation, and monitoring of corporate citizenship, environmental sustainability, climate change, and social and political trends, issues, and concerns. The Committee was integral in the development of Antero's 2025 environmental goals. These include a 50% reduction in our 2019 methane leak loss rate to under 0.025%, a 10% reduction in GHG intensity, and net zero Scope 1 carbon emissions through operational improvements, technologies, and carbon offsets.

We also published our annual Corporate Sustainability Report. This report highlights Antero's commitment to managing greenhouse gas emissions, reducing our use of fresh water, and the health and safety of our employees and communities. Antero continues to deliver industry-leading environmental results by demonstrating significant reductions in our greenhouse gas intensity, methane intensity, and methane leak loss rate from already low 2019 levels. Our strategic relationship with Antero Midstream provides access to an extensive network of pipelines and impoundments. This network has dramatically increased our ability to reuse and recycle produced water while also reducing the number of water trucks traversing on local



ANTERO IS ONE OF THE LARGEST SUPPLIERS TO THE GROWING LNG EXPORT BUSINESS IN THE U.S., WHICH DIRECTLY LEADS TO OUR PREMIUM NATURAL GAS PRICE REALIZATIONS.

roads, benefiting the local communities. We have earned a reputation as an industry-leading safe and environmentally responsible operator through our relentless focus on HSSE management and performance, making Antero an employer of choice in Appalachia.

As we look to the future, we believe that natural gas will be key to the energy transition over the coming decades. Natural gas complements renewable energy growth and powers the improvement in living standards across the globe. As the third largest natural gas producer in the U.S., we are well positioned to maintain our peer-leading ESG position and be a natural gas provider of choice. For additional information on Antero Resources' peer-leading ESG metrics, we encourage our shareholders to view our corporate sustainability report, which can be found at https://www.anteroresources.com/community-sustainability.

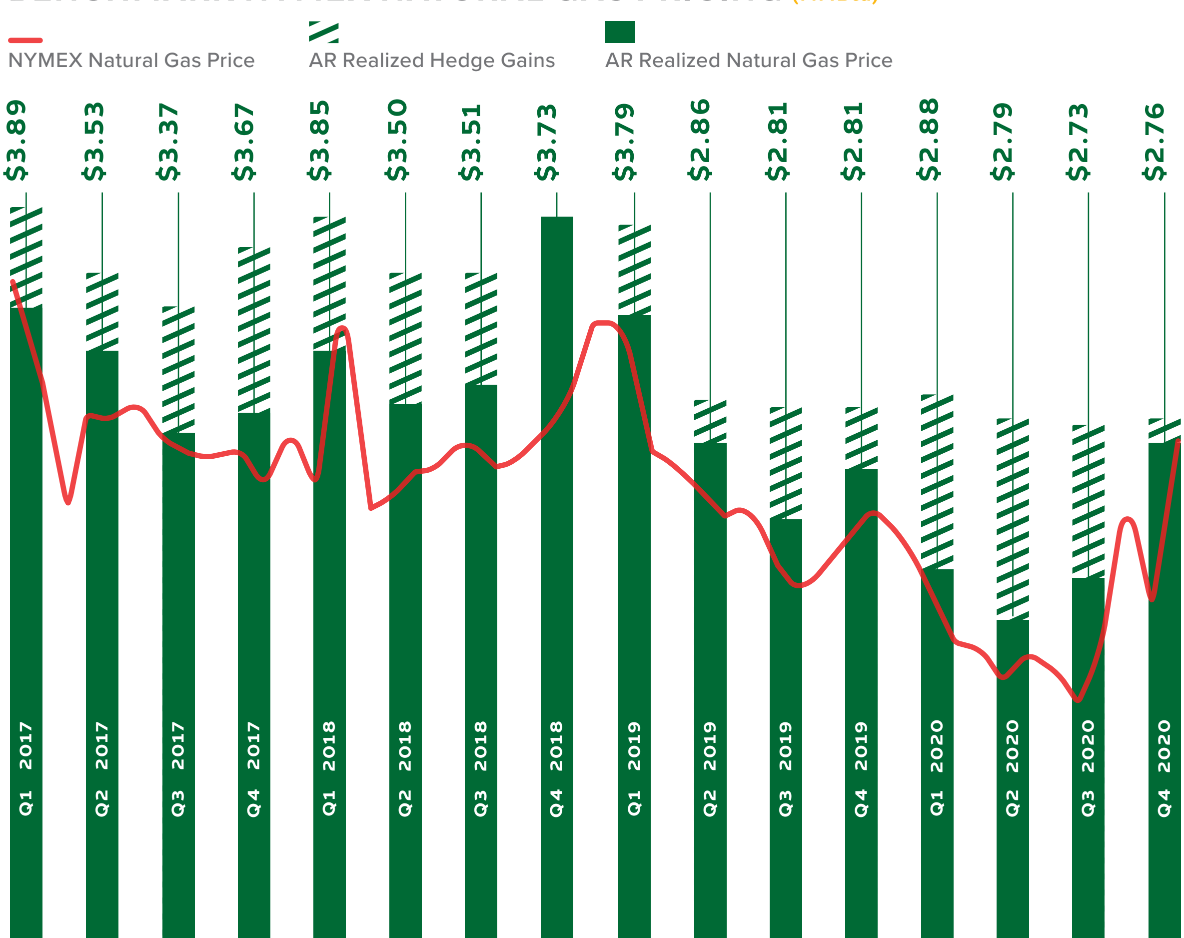
READY FOR THE FUTURE

Looking ahead, our development plan contemplates maintenance capital spending to maximize free cash flow generation and reduce absolute debt. In 2021, we are expecting gas-equivalent production to be held flat with a drilling and completion capital budget 20% below 2020. This is expected to result in substantial free cash flow during the year.

As one of the largest NGL producers in the United States, Antero is well positioned to capitalize on strong liquids pricing. Antero is also one of the largest NGL exporters. During 2021, we expect to sell at least 50% of our NGLs into the global markets, diversifying our liquids pricing exposure and providing another link to premium price realizations.

We also continue to deliver pre-hedge natural gas realizations at premium-to-benchmark pricing due to our firm transportation portfolio. Our 2.1 Bcf/d of transportation capacity to the Gulf Coast and 330 MMcf/d contracted to the Cove Point LNG terminal on the East Coast position Antero as one of the largest suppliers to the growing LNG export business in the U.S. This positioning allows us to receive premium natural gas realizations. To ensure stability in our gas revenues, we have built a substantial natural gas hedge position and will continue to hedge gas prices moving forward.

CONSISTENTLY DELIVERING ABOVE BENCHMARK NYMEX NATURAL GAS PRICING (MMBtu)



The combination of our large-scale diversified product pricing exposure, increased capital efficiency, and low leverage provides Antero with a differentiated strategy built to succeed throughout any commodity price cycle. Investors can remain confident in our coordinated development plan with Antero Midstream. This plan supports a low-risk, long-term outlook.

ANTERO MIDSTREAM DEVELOPMENTS

Antero Resources owns 29% of Antero Midstream Corporation's shares. Antero Midstream is an integrated midstream service provider whose primary role is to support the development plan of Antero Resources in Appalachia. Through its gathering and compression business, Antero Midstream delivers low-pressure gathering, compression, and high-pressure gathering services to Antero Resources. Antero Midstream also uses its fluid handling assets to manage fresh water delivery for well completions in addition to flowback and produced water for Antero Resources.

At year-end 2020, through the processing and fractionation joint venture with MPLX (NYSE: MPLX), the capacity at the Sherwood gas processing complex was increased to 3.2 Bcf/d, including 60,000 Bbl/d of de-ethanization capacity. Additionally, the joint venture has total fractionation capacity of 40,000 Bbl/d at the Hopedale fractionation complex.

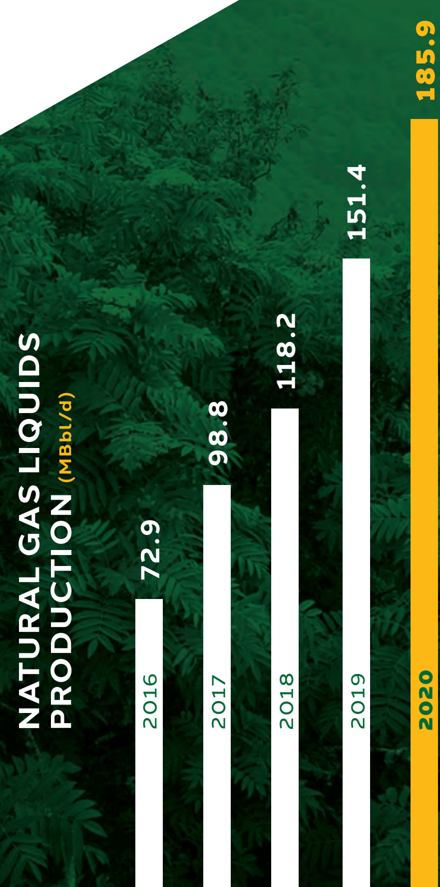
In 2020, Antero Midstream continued to build out its water handling and blending infrastructure footprint in the Marcellus and Utica Shale plays in West Virginia and Ohio, respectively, and now has a total fresh water delivery network of over 337 miles. This fresh water delivery system, the largest in Appalachia, eliminated more than 471,000 water truck trips in 2020 alone, significantly reducing Antero's environmental footprint.

OUR SHAREHOLDERS

We remain appreciative of the guidance and support of our Board of Directors. We thank you, our shareholders, for investing in our company and look forward to continued success in 2021, and for many years to come.

PAUL M. RADY
Chairman and CEO

GLEN C. WARREN, JR.
President and CFO



Antero Resources

2020

FORM 10K

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, 2020

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 to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant 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, 2020, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $584 million based on the $2.54 per share closing price of Antero Resources Corporation's common stock as reported on that day on the New York Stock Exchange.

The registrant had 301,189,530 shares of common stock outstanding as of February 12, 2021.

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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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

- our ability to execute our business strategy;
- our production and oil and gas reserves;
- our financial strategy, liquidity and capital required for our development program;
- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- natural gas, natural gas liquids ("NGLs"), and oil prices;
- impacts of world health events, including the coronavirus ("COVID-19") pandemic;
- timing and amount of future production of natural gas, NGLs, and oil;
- our hedging strategy and results;
- our ability to meet minimum volume commitments and to utilize or monetize our firm transportation commitments;
- our future drilling plans;
- our projected well costs and cost savings initiatives, including with respect to water handling services provided by Antero Midstream Corporation;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs, and oil;
- leasehold or business acquisitions;
- costs of developing our properties;
- operations of Antero Midstream Corporation;
- general economic conditions;
- credit markets;
- expectations regarding the amount and timing of jury awards;
- uncertainty regarding our future operating results; and

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

We caution investors that these forward-looking statements are subject to all of the risks and uncertainties incidental to our business, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, commodity price volatility, inflation, availability of drilling, completion and production equipment and services, environmental risks, drilling and completion and other operating risks, marketing and transportation risks, regulatory changes, 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 world health events, including the COVID-19 pandemic 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.

- Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and commodity prices do not improve, our cash flows may be adversely impacted. Furthermore, our derivative activities could result in financial losses or could reduce our earnings. In certain circumstances, we may have to make cash payments under our hedging arrangements and these payments could be significant.

- 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.

- The imbalance between the supply of and demand for oil, natural gas and NGLs has caused extreme market volatility and may result in increased costs and decreased availability of storage capacity. The lack of a market or available storage for certain of our products could cause interruptions in our operations, including temporary curtailments or shut-ins, or force us to sell our production at below-market prices, which 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.

- 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 58% 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.

Business Operations

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

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

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

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

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

- Increased attention to environmental, social and governance (“ESG”) matters and conservation measures may adversely impact our business.

- A pandemic, epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.

Customer Concentration and Credit Risk

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

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 our gas may adversely affect our business, financial condition and results of operations.

Acquisitions, Divestitures and Takeovers

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

Capital Structure and Access to Capital

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

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

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

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

Compliance with Regulations

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

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

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

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:

"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.

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

"*Btu*." British thermal unit.

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

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

"*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.

"*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.

"*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.

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

"*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.

"*Joint Venture*." The joint venture entered into on February 6, 2017 between Antero Midstream Partners LP, a wholly owned subsidiary of Antero Midstream and MarkWest Energy Partners, L.P. (*"MarkWest"*), a wholly owned subsidiary of MPLX, LP (*"MPLX"*), 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.

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

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

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

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

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

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

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

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

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

"MMcfe/d." MMcfe per day.

"*Net acres*." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% working interest in 100 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 and normal butane, and natural gasoline.

"*NYMEX*." The New York Mercantile Exchange.

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

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

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

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

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

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

"*PV-10*." When used with respect to oil and gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using average yearly prices computed using Securities and Exchange Commission ("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 generally accepted accounting principles ("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.

"*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.

"*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.

"*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.

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, 2020, we held approximately 515,000 net acres of natural gas, NGLs, and oil properties located in the Appalachian Basin primarily in West Virginia and Ohio. Our corporate headquarters are in Denver, Colorado.

Ownership in Antero Midstream

We formed Antero Midstream Partners LP ("Antero Midstream Partners") to own, operate and develop midstream energy assets that service our production. Antero Midstream Partners' assets consist of gathering systems and compression facilities, water handling and treatment facilities, and interests in processing and fractionation plants, through which it provides services to us under long-term, fixed-fee contracts.

On March 12, 2019, pursuant to the Simplification Agreement, dated as of October 9, 2018, by and among Antero Midstream GP LP ("AMGP"), Antero Midstream Partners and certain of their affiliates (the "Simplification Agreement") (i) AMGP was converted from a limited partnership to a corporation under the laws of the State of Delaware and changed its name to Antero Midstream Corporation (together with its consolidated subsidiaries, as appropriate, "Antero Midstream"), and (ii) an indirect, wholly owned subsidiary of Antero Midstream was merged with and into Antero Midstream Partners, with Antero Midstream Partners surviving the merger as an indirect, wholly owned subsidiary of Antero Midstream (together, along with the other transactions contemplated by the Simplification Agreement, the "Transactions"). In connection with the Transactions, we received $297 million in cash and 158.4 million shares of Antero Midstream's common stock in exchange for our 98,870,335 common units representing limited partner interests in Antero Midstream Partners owned immediately prior to the Transactions.

As a result of the Transactions, we no longer hold a controlling interest in Antero Midstream Partners and now have an interest in Antero Midstream that provides significant influence, but not control, over Antero Midstream. Thus, effective March 13, 2019, we no longer consolidate Antero Midstream Partners in our consolidated financial statements and account for our interest in Antero Midstream using the equity method of accounting. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for more information on the Transactions.

As of December 31, 2020, we owned 29.2% 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, 2020					Three Months Ended December 31, 2020
	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	17,635	$ 1,210	1,219	514,884	2,133	3,650
Discounted future income taxes [(6)]		—				
Standardized Measure [(7)]		$ 1,210				

(1) Estimated proved reserve volumes and values were calculated assuming partial ethane recovery, with rejection of the remaining ethane and using the unweighted twelve-month average of the first-day-of-the-month prices for the period ended December 31, 2020, which were $1.82 per MMBtu for natural gas based on a

$2.08 per MMBtu NYMEX reference price, $9.30 per Bbl for ethane, $14.31 per Bbl for C3+ NGLs and $30.03 per Bbl for oil for the Appalachian Basin based on a $39.72 per Bbl WTI reference price.

(2) Proved reserves for the noncontrolling interest in Martica Holdings LLC ("Martica") as of December 31, 2020 were 254 Bcfe. See "—Asset Sales Program" below for more information.

(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 21—Supplemental Information on Oil and Gas Producing Activities to the consolidated financial statements for more information about the calculation of standardized measure.

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

(5) Gross potential drilling locations are comprised of 256 locations classified as proved undeveloped, 1,877 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) Based on the 12-month average of the first-day-of-the-month prices used in the computation of PV-10 as of December 31, 2020, the future taxable net income generated over the life of our proved reserves is expected to be less than our net operating loss carryforward deductions, and therefore, under the standardized measure, there is no deduction for federal or state income taxes.

(7) Standardized measure of discounted future net cash flows for the noncontrolling interest in Martica as of December 31, 2020 was $359 million.

For the year ended December 31, 2020, our total consolidated capital expenditures were approximately $785 million, including drilling and completion expenditures of $735 million, leasehold additions of $48 million and other capital expenditures of $2 million. Our net capital budget for 2021 is $635 million. Our budget includes: $590 million for drilling and completion and $45 million for leasehold expenditures. We do not budget for acquisitions. During 2021, we plan to operate an average of three drilling rigs and two completion crews, and we plan to complete 65 to 70 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 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 project inventory.

Focused, Long-Lived Asset Base with Sufficient Takeaway Capacity

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

Integrated Business Platform

We operate in the following industry segments: (i) the exploration, development and production of natural gas, NGLs, and oil; (ii) marketing of excess firm transportation capacity; and (iii) midstream services through our equity method investment in Antero Midstream. As described above and elsewhere in this Annual Report on Form 10-K, effective March 13, 2019, the results of Antero Midstream Partners are no longer consolidated in our results. See Note 18—Segment Information to the consolidated financial statements for further discussion on our industry segment operations.

Hedge Program

We maintain an active hedging program designed to mitigate volatility in commodity prices and to protect our expected future cash flows for our future operations and capital spending plans. As of December 31, 2020, we had fixed price swap contracts in place for January 1, 2021 through December 31, 2023 for 1.2 Tcf of our projected natural gas production at a weighted average index price of $2.67 per MMBtu. These hedging contracts include contracts for the year ending December 31, 2021 of 788 Bcf of natural gas at a weighted average price of $2.77 per MMBtu. We also have fixed price swaps for the year ending December 31, 2021 for ethane for approximately 19 MMBbl at a weighted average index price of $0.20 per gallon and oil for approximately 3 MMBbl at a weighted average index price of $55.16 per Bbl. Additionally, we have basis swaps in place for January 1, 2021 through December 31, 2024 for 73 Bcf of our projected natural gas production with pricing differentials ranging from $0.414 to $0.53 per MMBtu. As of

December 31, 2020, the estimated fair value of our commodity net derivative contracts was approximately $22 million. See Note 12—Derivative Instruments to the consolidated financial statements for more information on our current hedge position.

Asset Sales Program

In December 2019, we announced an asset sale program of $750 million to $1 billion, the proceeds of which would be used to reduce indebtedness. Since December 2019, we have announced $751 million in asset sales, which includes up to $51 million of contingent consideration related to the ORRI transaction described below that may be earned in 2021. All proceeds from these assets sales were used for debt reduction, and any additional asset sales or excess cash flows are expected to be used for further debt reduction.

Conveyance of Overriding Royalty Interest

On June 15, 2020, we announced the consummation of a transaction with an affiliate of Sixth Street Partners, LLC (“Sixth Street”) relating to certain overriding royalty interests across our existing asset base (the “ORRIs”). In connection with the transaction, we contributed the ORRIs to a newly formed subsidiary, Martica, and Sixth Street at the initial closing 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 are achieved in the third quarter of 2020 and first quarter of 2021. All cash contributed by Sixth Street was distributed to us. During the third quarter of 2020, we met the applicable production threshold and received a $51 million cash distribution during the year ended December 31, 2020.

The ORRIs include an overriding royalty interest of 1.25% of our working interest in all of our 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 our working interest in all of our 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 we turn to sales 2.2 million lateral feet (net to our interest) of horizontal wells burdened by the Development Override and (b) the earlier of (i) April 1, 2023 and (ii) the date on which we turn to sales 3.82 million lateral feet (net to our interest) of horizontal wells are subject to the Development Override.

The ORRIs also include an additional overriding royalty interest of 2.00% of our working interest in the properties underlying the Initial PDP Override (the “Incremental Override”). The Incremental Override (or a portion thereof, as applicable) may be re-conveyed to us (at our election) if certain production targets attributable to the ORRIs are achieved through March 31, 2023. Any portion of the Incremental Override that may not be re-conveyed to us based on us achieving such production volumes through March 31, 2023 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 we will receive all distributions in respect of the Incremental Override, unless certain production targets are not achieved, in which case Sixth Street will receive some or all of the distributions in respect of the Incremental Override. Following Sixth Street achieving the Hurdle, we will receive 85% of the distributions in respect of the ORRIs to which Sixth Street was entitled immediately prior to the Hurdle being achieved.

Volumetric Production Payment Transaction

On August 10, 2020, we completed a volumetric production payment transaction and received net proceeds of approximately $216 million (the "VPP"). In connection with the VPP, we entered into a purchase and sale agreement, together with a conveyance agreement and production and marketing agreement, with J.P. Morgan Ventures Energy Corporation ("JPM-VEC") to convey, effective July 1, 2020, an overriding royalty interest in dry gas producing properties in West Virginia (the "VPP Properties") equal to 136,589,000 MMBtu over the expected seven-year term of the VPP.

We accounted for the VPP as a conveyance under Accounting Standard Codifications ASC Topic 932, *Extractive Industries—Oil and Gas*, and the net proceeds were recorded as deferred revenue. Revenue is recognized as volumes are delivered using the units-of-production method over the term of the VPP. Under the production and marketing agreement, we and our affiliates provide certain marketing services as JPM-VEC’s agent, and any income or expenses related to these services will be recorded as marketing revenue or marketing expenses as appropriate.

Contemporaneously with the VPP, we executed a call option related to the production volumes associated with our retained interest in the VPP properties, which is collateralized by a mortgage on the VPP properties. Additionally, the production and marketing agreement contains an embedded put option related to the production volumes for our retained interest in the VPP properties, which has been bifurcated from the production and marketing arrangement and accounted for as a derivative instrument recorded at fair value as of December 31, 2020. See Note 12—Derivative Instruments to the consolidated financial statements for further discussion of such derivative instruments.

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. Under the terms of the arrangement, QL will fund 20% of total development capital spending in 2021 and is expected to fund between 15% and 20% of total development capital spending on an annual basis from 2022 through 2024. All of the wells spud during each calendar year period will be a separate annual tranche. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche will be for our account.

For each tranche other than 2021, we will propose a capital budget and estimated internal rate of return ("IRR") for all wells to be spud during the year and, subject to the mutual agreement of the parties that the estimated IRR for each tranche exceeds a specified return, QL will be obligated to participate in such tranche. For each annual tranche in which QL participates, QL will receive a proportionate working interest percentage in each well spud in such tranche. If we present a capital budget for an annual tranche with an estimated IRR equal to or exceeding a specified return that QL in good faith believes is less than such specified return and QL elects not to participate, we will not be obligated to offer QL the opportunity to participate in subsequent tranches. No earlier than December 31 following the expiration of each tranche year, we will calculate the tranche IRR for such tranche year and, if the tranche IRR exceeds certain specified returns, we will receive a carry in the form of a one-time payment from QL for such annual tranche.

Our Properties and Operations

Reserves

The table below summarizes our estimated proved reserves as of December 31, 2019 and 2020, 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, 2019 (1)					
Proved developed reserves	7,229	731	21	11,740	62 %
Proved undeveloped reserves	4,265	460	21	7,153	38 %
Total	11,494	1,191	42	18,893	100 %
As of December 31, 2020 (2)					
Proved developed reserves (3)	6,901	810	19	11,873	67 %
Proved undeveloped reserves (4)	3,124	426	14	5,762	33 %
Total	10,025	1,236	33	17,635	100 %

(1) Unweighted 12 month average prices of the first-day-of-the-month for the period ended December 31, 2019 were $2.41 per MMBtu for natural gas, $10.59 per Bbl for ethane, $29.47 per Bbl for C3+ NGLs and $45.75 per Bbl for oil for the Appalachian Basin based on a $55.65 WTI reference price.

(2) Unweighted 12 month average prices of the first-day-of-the-month for the period ended December 31, 2020 were $1.82 per MMBtu for natural gas, $9.30 per Bbl for ethane, $14.31 per Bbl for C3+ NGLs, and $30.03 per Bbl for oil for the Appalachian Basin based on a $39.72 WTI reference price.

(3) Proved developed reserves for the noncontrolling interest in Martica as of December 31, 2020 were 181 Bcfe, which consisted of 110 Bcf of natural gas, 11 MMBbl of NGLs and 0.3 MMBbl of oil and condensate.

(4) Proved undeveloped reserves for the noncontrolling interest in Martica as of December 31, 2020 were 73 Bcfe, which consisted of 49 Bcf of natural gas, 4 MMBbl of NGLs and 0.2 MMBbl of oil and condensate.

Proved Reserves

The following table summarizes the changes in our estimated proved reserves during 2020 (in Bcfe):

Proved reserves, December 31, 2019	**18,893**
Extensions, discoveries, and other additions	1,105
Performance revisions	491
Revisions to five-year development plan	(790)
Price revisions	(1,126)
Sales of reserves in place	(113)
Revisions to ethane recovery	485
Production	(1,310)
Proved reserves, December 31, 2020	**17,635**

Extensions and discoveries of 1,105 Bcfe of proved reserves resulted from delineation and developmental drilling in the Appalachian Basin. Performance revisions resulted in a net upward revision of 491 Bcfe. Revisions to five-year development plan downward of 790 Bcfe include a downward revision of 922 Bcfe for locations that were not developed within five years of initial booking as proved reserves, partially offset by a net upward revision of 132 Bcfe from schedule optimization primarily driven by previously proved undeveloped properties reclassified from non-proved to proved undeveloped. Price revisions downward of 1,126 Bcfe are due to decreases in prices for natural gas, NGLs and oil. Sales of reserves of 113 Bcfe resulted from the VPP. Upward revisions to ethane recovery of 485 Bcfe are due to an increase in assumed future ethane recovery. Estimated proved reserves as of December 31, 2020 totaled 17,635 Bcfe, a decrease of 7% from the prior year.

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 during 2020 (in Bcfe):

Proved undeveloped reserves, December 31, 2019	**7,153**
Extensions, discoveries, and other additions	1,105
Performance revisions	172
Revisions to five-year development plan	(735)
Price revisions	(54)
Reclassifications to proved developed reserves	(1,967)
Revisions to ethane recovery	88
Proved undeveloped reserves, December 31, 2020	**5,762**

Extensions and discoveries during 2020 of 1,105 Bcfe of proved undeveloped reserves resulted from delineation and developmental drilling in the Appalachian Basin. Performance revisions resulted in a net upward revision of 172 Bcfe. Revisions to five-year development plan downward of 735 Bcfe included a downward revision of 927 Bcfe for locations that were not developed within five years of initial booking as proved reserves, partially offset by a net upward revision of 192 Bcfe from schedule optimization primarily driven by previously proved undeveloped properties reclassified from non-proved properties to proved undeveloped. Price revisions downward of 54 Bcfe are due to decreases in prices for natural gas, NGLs and oil. Upward revisions to ethane recovery of 88 Bcfe are due to an increase in assumed future ethane recovery.

During the year ended December 31, 2020, we converted approximately 1,967 Bcfe, or 27%, of our proved undeveloped reserves to proved developed reserves at a total capital cost of approximately $570 million. We spent an additional $253 million on development costs related primarily to drilled and uncompleted wells and properties in the proved undeveloped classification as of December 31, 2019, resulting in total development spending of $823 million, as disclosed in Note 21—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, 2020 are approximately $1.5 billion, or $0.27 per Mcfe, over the next five years. Based on strip pricing as of December 31, 2020, we believe that net cash provided by operating activities will be sufficient to finance such future development costs. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also continue drilling our proved undeveloped reserves. See "Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

We maintain a five-year development plan, which is reviewed by our Board of Directors, which supports our corporate production target. 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. In response to lower commodity prices, we reduced the pace of activity in our five-year development plan to a maintenance capital program. This resulted in the reclassification of 790 Bcfe of reserves from proved undeveloped to non-proved during the year ended December 31, 2020 due to the five-year development rule. Based on our then-current acreage position, strip prices, anticipated well economics, and our development plans at the time these reserves were classified as proved, we believe the previous classification of these locations as proved undeveloped was appropriate.

As of December 31, 2020, an estimated 11,342 of our net leasehold acres, containing 220 locations 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 approximately $31.4 million to renew the 11,342 acres based upon current leasing authorizations and option to extend payments. Proved undeveloped reserves of 913 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 approximately 137 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, 2018, 2019 and 2020 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"). We refer to D&M as our independent engineers. A copy of the summary report of D&M with respect to our reserves as of December 31, 2020 is filed as Exhibit 99.1 to this Annual Report on Form 10 K. The technical person at D&M primarily responsible for reviewing our reserves estimates was Dilhan Ilk, P.E. Mr. Ilk is a Registered Professional Engineer in the State of Texas (License No. 139334), is a member of the Society of Petroleum Engineers, and has in excess of 10 years of experience in oil and gas reservoir studies and reserves evaluations. Mr. Ilk graduated from the Istanbul Technical University in 2003 with a Bachelor of Science degree in Petroleum Engineering, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005 and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

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

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

Identification of Potential Well Locations

Our identified potential well locations represent locations to which proved, probable, or possible reserves were attributable based on SEC pricing as of December 31, 2020. We prepare internal estimates of probable and possible reserves but have not included disclosure of such reserves in this Annual Report on Form 10-K.

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, 2018, 2019 and 2020. 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,		
		2018	**2019**	**2020**
Production data (1) (2):				
Natural gas (Bcf)		710	822	875
C2 Ethane (MBbl)		14,221	15,861	19,709
C3+ NGLs (MBbl)		28,913	39,445	48,341
Oil (MBbl)		3,265	3,632	4,412
Combined (Bcfe)		989	1,175	1,310
Daily combined production (MMcfe/d)		2,709	3,220	3,578
Average prices before effects of derivative settlements:				
Natural gas (per Mcf)	$	3.22	2.74	2.07
C2 Ethane (per Bbl)	$	12.14	7.85	5.77
C3+ NGLs (per Bbl)	$	34.76	27.75	21.68
Oil (per Bbl)	$	57.33	48.88	25.45
Combined average sales prices before effects of derivative settlements (per Mcfe) (1)	$	3.69	3.10	2.35
Combined average sales prices after effects of derivative settlements (per Mcfe) (1)	$	3.94	3.38	2.96
Average Costs (per Mcfe) (3):				
Lease operating	$	0.14	0.13	0.08
Gathering, compression, processing, and transportation	$	1.81	1.92	1.93
Production and ad valorem taxes	$	0.12	0.11	0.08
Marketing, net	$	0.23	0.22	0.12
Depletion, depreciation, amortization, and accretion	$	0.85	0.76	0.66
General and administrative (excluding equity-based compensation)	$	0.13	0.12	0.08

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

(2) Average prices reflect the before and after effects of our settled commodity derivatives. Our calculation of such after effects includes gains on settlements of commodity derivatives (but does not include proceeds from the derivative monetizations in 2018 and 2020). These commodity derivatives do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. 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 does not necessarily reflect their relative economic value.

(3) Average costs prior to the deconsolidation of Antero Midstream Partners on March 12, 2019 have been adjusted to reflect our operating without eliminating intercompany transactions for midstream and water services provided by Antero Midstream Partners. Following the deconsolidation of Antero Midstream Partners, average costs reflect Antero's actual operating costs.

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, 2020. A majority of our developed acreage is subject to liens securing the Credit Facility. Approximately 75% 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.

Basin	Developed Acres		Undeveloped Acres [2]		Total Acres [2]	
	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin [1]	219,997	213,817	362,333	301,067	582,330	514,884

(1) Our acreage is located in West Virginia, Ohio and Pennsylvania.
(2) There are 44,309 gross (39,365 net), 49,589 gross (43,489 net) and 31,192 gross (26,745 net) acres subject to expiration during the years ending December 31, 2021, 2022 and 2023, 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

The following table summarizes gross and net productive wells as of December 31, 2020, all of which are natural gas wells. Net wells reflect the sum of our percentage ownership in gross wells.

	Year Ended December 31, 2020	
	Gross	Net
Appalachian Basin	1,516	1,462

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2018, 2019 and 2020. 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,					
	2018		2019		2020 [1]	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	153	151	123	122	106	104
Dry	—	—	—	—	—	—
Total development wells	153	151	123	122	106	104
Exploratory wells:						
Productive	10	10	8	8	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	10	10	8	8	—	—

(1) Well counts exclude 23 gross wells (21.8 net wells) that were drilled and uncompleted or in the process of being completed as of December 31, 2020.

Gathering and Compression

Our exploration and development activities are supported by the natural gas gathering and compression assets of Antero Midstream and by third-party gathering and compression arrangements. 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. For the years ended December 31, 2019 and 2020, Antero Midstream spent approximately $316 million and $158 million, respectively, on gas gathering and compression infrastructure that services our production. 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, 2020, Antero Midstream owned and operated 468 miles of gas gathering pipelines in the Appalachian Basin. We also have access to additional low-pressure and high-pressure pipelines owned and operated by third parties. As of December 31, 2020, Antero Midstream owned and operated 20 compressor stations, and we utilized 16 additional third-party compressor stations. The gathering, compression, and dehydration services provided by third parties are contracted on a fixed-fee basis.

Natural Gas Processing

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

NGLs are valuable commodities once removed from the natural gas stream in a cryogenic processing facility yielding y-grade liquids. Y-grade liquids are then fractionated, thereby breaking up the y-grade liquid into its key components. Fractionation refers to the process by which an NGL y-grade stream is separated into individual NGL 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 a joint venture with MarkWest 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	Q3 2021 (2)
Seneca 1 through 4	800	600	In service
Total	3,600	3,400	

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

(2) Anticipated contractual start date.

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”). The firm transportation contract on REX provides firm capacity for 600,000 MMBtu per day and delivers gas to downstream contracts on MGT, NGPL, and ANR. On October 1, 2021, firm transportation capacity will be reduced to 400,000 MMBtu per day.

We have 265,000, 310,000 and 200,000 MMBtu per day of firm transportation on MGT, NGPL and ANR, respectively. On September 30, 2021, MGT contracts will be reduced to 125,000 MMBtu per day. The MGT and NGPL contracts deliver gas to the Chicago city gate area and the ANR contract delivers natural gas to Chicago in the summer and Michigan in the winter. The Chicago and Michigan contracts expire at various dates from 2021 through 2035.

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) DTE Energy’s Stonewall Gas Gathering (“SGG”), (iv) Tennessee Gas Pipeline (“Tennessee”), (v) ANR Pipeline (“ANR-Gulf” or “ANR-Chicago”), (vi) Energy Transfer Rover Pipeline (“ET Rover”), (vii) Equitrans pipeline (“EQT”), (vii) Texas Eastern Transmission Corp. - M2 Zone (“TETCO M2”) (viii) DTE Energy’s Appalachia Gathering System (“AGS”), (ix) Mountaineer Xpress pipeline (“MXP”), (x) Columbia Gas Transmission IPP pool (“TCO IPP”), (xi) Gulf Xpress pipeline (“GXP”), (xii) Enterprise Products Partners ATEX pipeline (“ATEX”) and (xiii) Sunoco pipeline (“Mariner East 2”). Our diverse portfolio of firm capacity gives us the flexibility to move natural gas to the local Appalachia market or other preferred markets with more favorable pricing. These firm capacity contracts include:

- TCO firm capacity of approximately 584,000 MMBtu per day. On March 31, 2021, firm capacity will be reduced to 474,000 MMBtu per day. Of the 584,000 MMBtu per day of firm capacity on TCO, we have the ability to utilize 530,000 MMbtu per day on Columbia Gulf, which provides access to the Gulf Coast markets. These contracts expire at various dates from 2021 through 2058.

- SGG firm capacity of 900,000 MMBtu per day which transports gas from various gathering system interconnection points and the MarkWest Sherwood plant complex to the TCO WB System. Additionally, we have firm transportation contracts with TCO for both the western and eastern directions on the pipeline. Our firm capacity of 800,000 MMBtu per day west bound on TCO (“TCO WB”) provides us access to the local Appalachia and the Gulf Coast markets via the Columbia Gulf or Tennessee pipelines. Our firm capacity of 330,000 MMBtu per day east bound on TCO delivers natural gas to the Cove Point LNG facility These contracts expire at various dates from 2033 through 2038.

    - Tennessee firm capacity of 790,000 MMBtu per day to deliver natural gas from the Broad Run interconnect on TCO WB to the Gulf Coast market. This contract expires in 2030.

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

    - ET Rover Pipeline firm capacity of 840,000 MMBtu per day, which connects the Appalachian Basin to Midwest and Gulf Coast markets via the ANR Chicago and ANR Gulf. These contracts expire at various dates from 2025 through 2033.

    - EQT firm capacity of 250,000 MMBtu per day to deliver natural gas to TETCO M2 and other various delivery points. These contracts expire at various dates from 2022 through 2025.

- AGS firm capacity of 275,000 MMBtu per day to deliver natural gas to TETCO M2 and other various local delivery points. These contracts expire in 2023.

- MXP firm capacity of 700,000 MMBtu per day to deliver (i) 517,000 MMBtu per day to TCO IPP and (ii) 183,000 MMBtu per day to GXP which continues to Leach, Kentucky. These contracts allow us to deliver natural gas to the U.S. Gulf Coast and they expire in 2034.

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

- Mariner East 2 firm capacity for ethane of 11,500 Bbl per day and propane and butane of 55,000 Bbl per day to deliver to Marcus Hook, Pennsylvania. These contracts expire November 2028 and February 2029, respectively. The propane and butane contract increases 5,000 Bbl per day each year through 2022, resulting in an ultimate total firm capacity of 65,000 Bbl per day. 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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations" for information on our minimum fees for such contracts. Based on current projected 2021 annual production guidance, we estimate that we could incur annual net marketing costs of $0.08 per Mcfe to $0.10 per Mcfe in 2021 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, 2020, our firm sales commitments through 2025 included:

Year Ending December 31,	Natural Gas (MMBtu/d)	Ethane (Bbl/day)	C3+ NGLs (Bbl/day)	Condensate (Bbl/day)
2021	900,000	51,500	52,295	28,000
2022	780,000	106,500	23,000	—
2023	690,000	101,500	5,000	—
2024	600,000	96,500	5,000	—
2025	600,000	85,500	5,000	—

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 "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations."

Water Handling and Treatment Operations

Our agreements with Antero Midstream allow us to obtain the necessary raw, fresh and recycled water (collectively, "fresh water") for use in our drilling and completion operations, as well as services to dispose of wastewater 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 fresh water storage facilities, as well as pumping stations to transport the fresh water throughout the pipeline networks. The surface pipelines are moved to well pads to service completion operations to the extent necessary and feasible. As of December 31, 2020, Antero Midstream had the ability to store 5.7 million barrels of fresh water in 37 impoundments located throughout our leasehold acreage. Due to the extensive geographic distribution of Antero Midstream's water pipeline systems in the Appalachian Basin, it is able to provide water delivery services to neighboring oil and gas producers within and adjacent to our operating area, subject to commercial arrangements, while reducing water truck traffic.

As of December 31, 2020, Antero Midstream owned and operated 203 miles of buried fresh water pipelines and 134 miles of portable surface fresh water pipelines in the Appalachian Basin, as well as 37 fresh water storage facilities equipped with transfer pumps. Through Antero Midstream, we also recycle and reuse the majority of our flowback and produced water through blending.

Major Customers

Our sales to major customers (purchasers in excess of 10% of total sales) for the years ended December 31, 2018, 2019 and 2020 were as follows:

Year Ended December 31, 2018	
Mercuria Energy America, Inc.	14 %
Tenaska Marketing Ventures	13 %
Year Ended December 31, 2019	
Sabine Pass Liquefaction LLC	16 %
WGL Midstream	15 %
Year Ended December 31, 2020	
Sabine Pass Liquefaction LLC	11 %
WGL Midstream	11 %

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, cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and 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, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. Cold winters can significantly increase demand and price 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 exclusively on private lands and 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, the states, 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 and Ohio, 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 Federal Energy Regulatory Commission (“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 as a natural gas company under the NGA. 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 include 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 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: (1) 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; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-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 per day for each violation of the NGA and the NGPA. In January 2021, FERC issued an order (Order No. 875) 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 approximately $1.3 million 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 $1.2 million (adjusted annually for inflation) per violation per day. Together with FERC, these agencies have imposed broad rules and regulations prohibiting fraud and manipulation in oil and gas markets and energy futures markets.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe that any regulatory changes will affect us materially differently from the way they will affect our competitors.

Regulation of Environmental and Occupational Safety and Health Matters

General

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

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

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In addition, despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we generate materials in the course of our operations that may be regulated as hazardous substances based on their characteristics; however, we are unaware of any liabilities arising under CERCLA for which we may be held responsible that would materially and adversely affect us.

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

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

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (the "CWA"), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state equivalent agency. 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. In September 2015, the EPA and U.S. Army Corps of Engineers issued a final rule defining the scope of the EPA's and the Corps' jurisdiction over waters of the U.S. (the "WOTUS rule"). Following the change in U.S. Presidential Administrations, there have been several attempts to modify or eliminate this rule. For example, on January 23, 2020, the EPA and the Corps finalized the Navigable Waters Protection Rule, which narrows the definition of "waters of the United States" relative to the prior 2015 rulemaking. However, both this and prior rulemakings regarding the definition of WOTUS are currently subject to litigation, and it is possible that the Biden Administration could propose a broader interpretation of the CWA's jurisdiction. As a result of these developments, the scope of jurisdiction under the CWA is uncertain at this time. To the extent any rule expands the scope of the CWA's jurisdiction in areas where we operate, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which could delay the development of our natural gas and oil projects. Similarly, any increased costs or delays for such permits may impact the development of pipeline infrastructure, which may impact our ability to transport our products. Also, pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants, the costs of which could be significant. The need to obtain permits has the potential to delay the development of our oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS"), for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards, and completed attainment/non-attainment designations in July 2018. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Separately, in June 2016, the EPA finalized rules under the federal Clean Air Act regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities (such as tank batteries and compressor stations), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install additional costly pollution control equipment. The EPA has also issued final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants programs. These final rules require, among other things, capturing or combustion of certain emissions, as well as emission leak detection and repair programs. These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such current requirements will have a material adverse effect on our operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs"), present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD"), construction and Title V operating permit reviews for certain large stationary sources that are already major sources of criteria pollutant emissions regulated under the statute. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA for those emissions. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. For example, in December 2015, the EPA finalized rules that added new sources to the scope of the GHG monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule.

In June 2016, the EPA finalized new regulations, known as Subpart OOOOa, that establish emission standards for methane and VOCs from new and modified oil and natural gas production and natural gas processing and transmission facilities. The EPA's rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rule package extends existing VOC standards under the EPA's Subpart OOOO of the NSPS ("NSPS Quad O"), to include previously unregulated equipment within the oil and natural gas source category. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified, and existing oil and gas facilities. Given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities.

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

For example, in 2017, Antero incorporated a balanced drill out technique as the first 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 long history of managing methane emissions from our operations, as demonstrated by our early use of emission reduction techniques and equipment.

When we permit a facility, we install air pollution control equipment in an effort 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 down 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 also install low-bleed pneumatic controllers, which minimize methane emissions.

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.

For years 2017, 2018 and 2019, we published an annual Corporate Sustainability Report ("CSR"), which highlights our most significant environmental program improvements and initiatives. As highlighted in our CSR, our methane leak loss rate in 2019 was 0.046%, well below the industry target of 1%.

During 2020, our GHG/methane emission reduction efforts included the following activities:

1) The GHG/Methane Reduction team met on a quarterly basis to review emerging methane detection and quantification technologies applicable to exploration and production operations.

2) Facility LDAR inspections were conducted at twice the frequency required by regulation.

3) Implemented the use of lockdown thief hatches on storage tanks at all new production facilities.

4) Operation of burner management systems with three stages of pressure control to optimize combustor efficiency. We utilize combustors that are certified by the manufacturer to meet EPA performance standards.

5) Operation of three stages of pressure control on our storage tanks.

6) Utilization of vapor recovery systems such that we now incorporate up to three stages of vapor recovery in our process.

7) Use of low pressure separators (Green Completion Units) after drill out during separation flowback operations to recover methane and send it down a sales line. This enables us to recover a salable product and reduce methane emissions during completion operations.

8) Pressure relief valves are tested and repaired or replaced as necessary, reducing the amount of methane that is accidently released.

9) Balanced well drill outs, which minimize the potential for venting and/or flaring of gas from our wells during the well completion process.

10) Periodic plugging and abandoning of certain older vertical wells that were acquired in conjunction with property acquisitions. Plugging and abandoning older, low producing wells can reduce methane emissions.

11) Transition from intermittent and low-bleed air-controlled pneumatics at all new production facilities and select existing pads where purchased power was available.

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.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, President Biden has highlighted addressing climate change as a priority of his administration, which includes certain potential initiatives for climate change legislation to be proposed and passed into law. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across agencies and economic sectors. Other actions that could be pursued by the Biden Administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. Internationally, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. Although the United States had withdrawn from the Paris Agreement, President Biden has issued executive orders recommitting the United States to the Paris Agreement and directing the federal government to begin formulating the United States' nationally determined emissions reduction target under the agreement. The impacts of this order, and any legislation or regulation promulgated to fulfill the United States commitments under the Paris Agreement, are unclear at this time. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing and marketing fuels that contributed to global warming effects and therefore are responsible for damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time and defrauded their investors or customers by failing to adequately disclose those impacts.

Additionally, our access to capital may be impacted by climate change policies. Financial institutions may adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. For example, the Federal Reserve recently announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. While we cannot predict what policies may result from this, a material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could impact our business and operations. Finally, it should be noted that a number of scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

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

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

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities, and citizens.

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 April 2015, the USFWS listed the northern long-eared bat, whose habitat includes the areas in which we operate, as a threatened species under the ESA; however, on January 28, 2020, the U.S. District Court for the District of Columbia ordered the USFWS to reconsider its decision to list the northern long-eared bat as threatened instead of endangered. 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 2020, nor do we anticipate that such expenditures will be material in 2021.

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, 2020, we had 522 full-time employees, including 41 in executive, finance, treasury, legal and administration, 22 in information technology, 14 in geology, 214 in production and operations, 140 in midstream and water, 51 in land and 40 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, wages and 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 15 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; and
- wellness support benefits including an employee assistance program and short-term and long-term disability coverage, 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 and development opportunities. We provide training by department to focus on job and area specific training. 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 through the annual contractor safety conference where 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.

In response to the COVID-19 pandemic, we have implemented significant changes that we believe to be in the best interest of our employees, as well as the communities in which we operate, and that comply with government orders. These include having our office employees work from home to the extent they are able and implementing additional safety measures, including required weekly testing and other recommended public health measures for our field and other employees (including on-site contract workers) continuing critical on-site work.

Diversity, Inclusion and Workplace Culture

We are committed to building a culture where diversity and inclusion are core philosophies across our operations, including, but not limited to, our decisions around recruitment, promotion, transfer, leaves of absence, compensation, opportunities for career support and advancement, job performance and other relevant job-related criteria. We embrace an approach to hiring and advancement that considers the value of diversity, and we are also committed to making opportunities for development and progress available to all employees so their talents can be fully developed to maximize our and their success. We believe that creating an environment that cultivates a sense of belonging requires encouraging employees to continue to educate themselves about each other's experiences, and we strive to promote the respect and dignity of all persons. We also believe it is important that we foster education, communication and understanding about diversity, inclusion and belonging. Finally, in line with our commitments to equal employment opportunity and diversity and inclusion, we expect recruiters operating on our behalf to provide us with a diverse pool of candidates.

Address, Internet Website and Availability of Public Filings

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

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

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

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

ITEM 1A. RISK FACTORS

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

Commodity Prices

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

The prices we receive for our natural gas, NGLs, and oil production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs, and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for these commodities have been volatile. These markets will likely continue to be volatile in the future. 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 (e.g., the reduced demand resulting from the COVID-19 pandemic);
- prevailing prices on local price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $3.14 per MMBtu to a low of $1.33 per MMBtu in 2020, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $63.27 per barrel to a low of negative $36.98 per barrel during the same period. 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, similar to the aggregate $1.3 billion impairment charges we recognized in 2019. 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.

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and commodity prices do not improve, our cash flows may be adversely impacted. Furthermore, our derivative activities could result in financial losses or could reduce our earnings. In certain circumstances, we may have to make cash payments under our hedging arrangements and these payments could be significant.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2020, we had entered into forward swap contracts for approximately 1.2 Tcfe of our projected natural gas production through December 31, 2023 and basis swap contracts for approximately 73 Bcfe through December 31, 2024. Historically, we have realized a significant benefit from our hedge positions. For example, for the years ended December 31, 2019 and 2020, we received approximately $325 million and $795 million, respectively, in revenues from cash settled derivatives pursuant to our hedging arrangements, including $9 million for certain natural gas hedges that were monetized prior to their contractual settlement dates during the year ended December 31, 2020. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2019 and 2020 were executed at times when spot and future prices were higher than prices that we are currently able to obtain in the futures market, and the prices at which we have been able to hedge future production have decreased as a result. Sustained weaknesses in commodity prices adversely affect our ability to hedge future production. If we are unable to enter into new hedge contracts in the future at favorable pricing and for sufficient volumes, our financial condition and results of operations could be materially adversely affected.

Additionally, because we have financial derivatives in place to hedge against price declines for a significant part of our estimated future production, we have fixed or limited a significant part of our overall future revenues. Assuming our 2021 production is the same as our production in 2020, approximately 92% of our production for 2021 will be hedged through either forward swaps or basis swaps. If natural gas 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 for our natural gas contracts. For example, during the year ended December 31, 2020, we paid approximately $19 million, net, related to cash settled derivatives pursuant to our hedging arrangements due to increased commodity prices. If development drilling costs increase significantly because of inflation, increased demand for oilfield services, increased costs to comply with regulations governing our industry or other factors, the payments we receive under these derivative contracts may not be sufficient to cover our costs.

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. For example, see the discussion of the impairment charges we recorded in 2018 and 2019 with respect to our Utica Shale properties in Note 2—Significant Accounting Policies to the consolidated financial statements. 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.

The imbalance between the supply of and demand for oil, natural gas and NGLs has caused extreme market volatility and may result in increased costs and decreased availability of storage capacity. The lack of a market or available storage for certain of our products could cause interruptions in our operations, including temporary curtailments or shut-ins, or force us to sell our production at below-market prices, which could adversely affect our financial condition and results of operations.

The marketing of our natural gas, NGLs, and oil production is substantially dependent upon the existence of adequate markets for our products. In response to the COVID-19 pandemic, governments have tried to slow the spread of the virus by imposing social distancing guidelines, travel restrictions and stay-at-home orders, which have caused a significant decrease in the demand for natural gas, NGLs, and oil. The imbalance between the supply of and demand for these products, as well as the uncertainty around the extent and timing of an economic recovery have caused extreme market volatility and a substantial adverse effect on commodity prices. Also, as a result of this imbalance, the industry has experienced and may experience in the future storage capacity constraints with respect to certain NGL products and oil. If we are unable to sell our production or enter into additional storage arrangements on commercially reasonable terms or at all, we could be forced to temporarily shut in a portion of our production, or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons or sell our production at below-market prices. Although our production is more heavily weighted to natural gas, the lack of a market or available storage for any one NGL product or oil could result in temporary shut-ins as we may be unable to curtail the production of individual products in a meaningful way without reducing the production of other products. We are unable to determine the extent or duration of any such curtailments. Any such shut in or curtailment, or any inability to obtain favorable terms for delivery of the natural gas, NGLs and oil we produce, 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, 2020, 33% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 5.8 Tcfe of estimated proved undeveloped reserves will require an estimated $1.5 billion of development capital over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could require us to reclassify our proved undeveloped reserves as unproved reserves.

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

The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

To prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as realized prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

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

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

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

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

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

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore, our future cash flow and results of operations are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire sufficient additional reserves to replace our current and future production, and any such acquisition and development may be offset by any asset disposition, including those contemplated by our asset sale program. 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 58% 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 58% 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 913 Bcfe related to such acreage that is subject to renewal prior to drilling. In addition, approximately 25% 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, cyber-attacks 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. 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, 2020, we had 2,133 identified potential horizontal well locations located 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 in the properties in which we invest.

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 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 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.

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

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

Moreover, while we create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our stock price and our access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

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 2021 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 2021 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 2021 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.

A pandemic, epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.

The global or national outbreak of an infectious disease, such as COVID-19, 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, to address the COVID-19 pandemic 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 COVID-19 and concerns regarding its global spread have negatively impacted global demand for crude oil and natural gas, which has and could continue to contribute to price volatility, 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 the COVID-19 pandemic 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 or cyber-attacks and threats could have a material adverse effect on our business, financial condition or results of operations.

Terrorist or cyber-attacks 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. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Our insurance may not protect us against such occurrences. We depend on digital technology in many areas of our business and operations, including, but not limited to, estimating quantities of oil and gas reserves, processing and recording financial and operating data, oversight and analysis of drilling operations, and communications with our employees and third-party customers or service providers. Deliberate attacks on our assets, or security breaches in our systems or infrastructure, or the systems or infrastructure of third-parties or the cloud, could lead to the corruption or loss of our proprietary and potentially sensitive 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 and third-party liabilities. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, ransomware, attempts to gain unauthorized access to data and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data.

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

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, 2020, 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.

Customer Concentration and Credit Risk

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

As of December 31, 2020, the estimated fair value of our commodity net derivative contracts was approximately $22 million, and included the following net derivative assets by bank counterparty: Morgan Stanley - $35 million; Canadian Imperial Bank of Commerce - $25 million; Scotiabank - $14 million; Natixis - $5 million; DNB Capital - $2 million; and Truist $1 million.

As described above, we enter into certain derivative instruments in the ordinary course operations of our business. 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. Derivative instruments also 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.

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

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

In addition to credit risk related to receivables from commodity derivative contracts, 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 ($380 million as of December 31, 2020). 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, 2020 accounted for approximately 11% 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.

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 2021 to 2058 and our gas processing, gathering, and compression services agreements expire at various dates from 2021 to 2038. We are obligated to pay fees on minimum volumes to certain of our service providers regardless of actual volume throughput. As of December 31, 2020, our long-term contractual obligations under agreements with minimum volume commitments totaled over $12.7 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 2021 production is unchanged from 2020 production, we estimate that we will incur annual net marketing costs of $0.08 per Mcfe to $0.10 per Mcfe in 2021 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 the gas gathering and compression agreement that we have entered into 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 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.

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

We have agreements with processing facilities, including those owned by MPLX and the Joint Venture, to accommodate our current operations as well as future development plans. Any significant interruptions at these facilities 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 could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within the operator's control, such as:

- unscheduled turnarounds 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 NGL products; and
- terrorist or cyber-attacks.

Acquisitions, Divestitures and Takeovers

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

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

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

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

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) the Sponsors 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) the Sponsors and their affiliates are permitted to have interests in, participate with, aid and maintain seats on the boards of directors or similar governing bodies of any such investments, in each case that may, are or will be competitive with our business and the business of our subsidiaries or in the same or similar lines of business as us and our subsidiaries, or that could be suitable for us or our subsidiaries and (iii) we have, subject to limited exceptions, renounced, to the fullest extent permitted by law, any interest or expectancy in, or in being offered an opportunity to participate in, such corporate opportunities;

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

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

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

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

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

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

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

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

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

Paul M. Rady, Glen C. Warren, Jr. and certain funds affiliated with Yorktown (collectively, the "Sponsors") in the aggregate own a significant number of shares of common stock of Antero Midstream. Messrs. Rady and Warren and an individual affiliated with Yorktown serve as members of our board of directors and the board of directors of Antero Midstream. The Sponsors also own a significant portion of the shares of our common stock. As a result of their investments in Antero Midstream, the Sponsors may have conflicting interests with other stockholders. Conflicts of interest could arise in the future between us, on the one hand, and the Sponsors, on the other hand, regarding, among other things, decisions related to our financing, capital expenditures and business plans, the terms of our agreements with Antero Midstream and its subsidiaries and the pursuit of potentially competitive business activities or business opportunities.

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

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

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

Our business and financing plans may periodically include divesting certain assets. However, we do not completely control the timing of divestitures, and delays in completing divestitures may reduce the benefits we may receive from them, such as reducing management distractions by selling non-core assets and the receipt of cash proceeds that reduce debt and contribute to our liquidity.

Various factors could materially affect our ability to dispose of assets if and when we decide to do so, including the availability of purchasers willing to purchase the assets at prices acceptable to us, particularly in times of reduced and volatile commodity prices.

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 related to drilling, completions, and land expenditures was approximately $871 million in 2020. Our board of directors has approved a net capital budget for 2021 of $635 million that includes $590 million for drilling and completion and $45 million for leasehold expenditures. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations, and dividends from Antero Midstream, which we do not control the timing or amount of, if any; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The actual amount and timing of our future capital expenditures may differ materially from our capital budget as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological, and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to maintain production. For additional discussion of the risks regarding our ability to obtain funding, please read "—The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility."

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

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

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

If our revenues or the borrowing base under the Credit Facility decrease as a result of sustained periods of low natural gas, NGLs, and oil prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flows generated by our operations or available borrowings under the Credit Facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

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

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

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

The borrowing base under the Credit Facility is currently $2.85 billion, and lender commitments under the Credit Facility are $2.64 billion. Our borrowing base is redetermined semi-annually by the lenders each April and October based on certain factors, including our reserves and hedge position, with the next borrowing base redetermination scheduled to occur in April 2021. Our borrowing base may decrease as a result of a decline in natural gas, NGLs, or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which could have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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

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

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

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

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

- sell assets;
- make loans to others;
- make investments;

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

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

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

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

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, during 2020, we had estimated average outstanding borrowings under the Credit Facility of approximately $871 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 approximately $8.7 million and a corresponding decrease in our cash flows and net income before the effects of income taxes. Furthermore, a downgrade to our credit rating would trigger certain obligations to deliver letters of credit to certain transactional counterparties, which would adversely impact our available liquidity. Disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. A significant reduction in net cash provided by operating activities or the availability of credit could materially and adversely affect our ability to achieve our development plan and operating results.

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

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

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

Compliance with Regulations

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

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

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

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

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

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

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

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

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production, processing and transportation of natural gas, NGLs, and oil. For example, following the election of President Biden and a Democratic majority in both houses of Congress, it is possible that our operations may be subject to greater environmental, health and safety restrictions, particularly with regards to hydraulic fracturing, permitting and GHG emissions. 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 approximately $1.3 million 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.

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

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

In June 2016, the EPA finalized new regulations, known as Subpart OOOOa, that establish emission standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. The EPA's rule package included first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rule package extended existing VOC standards under the EPA's Subpart OOOO to include previously unregulated equipment within the oil and natural gas source category. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified, and existing oil and gas facilities. 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.

Additionally, President Biden has issued executive orders recommitting the United States to the Paris Agreement and directing the federal government to begin formulating the United States' nationally determined emissions reduction target under the agreement. The impacts of this order, and any legislation or regulation promulgated to fulfill the United States commitments under the Paris Agreement, cannot be predicted at this time.

Concern over the threat of climate change has also resulted in increasing political risks in the United States, including climate-change related pledges made by President Biden and other public office representatives. These have included promises to pursue actions to limit emissions and curtail the production of oil and gas, such as through the cessation of leasing federal land for hydrocarbon development. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across agencies and economic sectors. Other actions that could be pursued include more restrictive requirements for the development of pipeline infrastructure or LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities.

Increasingly, fossil fuel companies are also exposed to litigation risks associated with the threat of climate change. A number of cities and other local governments have brought suits against the largest fossil fuel companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change. Suits have also been brought against such companies under shareholder and consumer protection laws, alleging that the companies have been aware of the adverse effects of climate change but failed to adequately disclose those impacts. We are not currently party to any such litigation, but could be named in future actions making similar claims of liability. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Additionally, in response to concerns related to climate change, companies in the fossil fuel sector 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-fossil fuel related sectors. Institutional lenders who provide financing to fossil-fuel energy companies have also become more attentive to sustainable lending practices, and some of them may elect in future not to provide funding for fossil fuel energy companies. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Recently, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. A material reduction in the capital available to the fossil fuel 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.

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

Finally, it should be noted that a number of scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events; if any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our exploration and production operations. In addition, while our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

Regulations related to the protection of wildlife adversely 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, on January 28, 2020, the U.S. District Court for the District of Columbia ordered the USFWS to reconsider its decision to list the northern long-eared bat as threatened instead of endangered. 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 Paul M. Rady, our Chairman and Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer, 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.

Income Taxes

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

As of December 31, 2020, we have U.S. federal and state NOL carryforwards of $2.3 billion and $2.0 billion, respectively, some of which expire at various dates from 2032 to 2040 while others have no expiration date. We currently expect to be able to utilize these NOL carryforwards and generate deductions to offset our future taxable income. This expectation is based upon assumptions we have made regarding, among other things, our income, capital expenditures and net working capital, and upon our NOL carryforwards not becoming subject to future limitation under Section 382 of the Internal Revenue Code of 1986, as amended ("***Section 382***"), or otherwise.

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

Furthermore, any significant variance in our interpretation of current income tax laws, including as result of the release of final Treasury Regulations or other interpretive guidance implementing the Tax Cuts and Jobs Act, or a challenge of one or more of our tax positions by the IRS or other tax authorities could affect our tax position. While we expect to be able to utilize our NOL carryforwards and generate deductions to offset our future taxable income, in the event that deductions are not generated as expected, one or more of our tax positions are successfully challenged by the IRS (in a tax audit or otherwise), or our NOL carryforwards are subject to future limitation (including due to an ownership change under Section 382), our future tax liability may be greater than expected.

Potential future legislation or the imposition of new or increased taxes or fees may generally affect the taxation of natural gas and oil exploration and development companies and may adversely affect our operations and cash flows.

In past years, 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 available to natural gas and oil exploration and development companies. For example, President Biden has set forth several tax proposals that would, if enacted into law, make significant changes to U.S. tax laws. Such proposals include, but are not limited to, (i) an increase in the U.S. income tax rate applicable to corporations and (ii) the elimination of tax subsidies for fossil fuels. Congress could consider some or all of these proposals in connection with tax reform to be undertaken by the Biden administration. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on natural gas and oil extraction. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws or the imposition of new or increased taxes or fees on natural gas and oil extraction could adversely affect our operations and cash flows.

General Risks

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

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

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

- our operating and financial performance and prospects and the trading price of our common stock;
- the level of any dividends we may declare;
- quarterly variations in the rate of growth of our financial indicators, such as net income and revenues;
- levels of indebtedness;
- changes in revenue or earnings estimates or publication of research reports by analysts;
- speculation by the press or investment community;
- sales of our common stock by other stockholders;
- announcements by us or our competitors of significant contracts, acquisitions, strategic partnerships, joint ventures, securities offerings or capital commitments;

- general market conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- adverse changes in tax laws or regulations; and
- domestic and international economic, legal and regulatory factors related to our performance.

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

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

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

We are not restricted from issuing additional shares of our common stock out of our authorized capital. In the future, we may issue shares of our common stock to raise cash for future activities, acquisitions or other purposes. We may also acquire interests in other companies by using a combination of cash and shares of our common stock or only shares. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, shares of our common stock. For example, the 2026 Convertible Notes may become convertible at the option of holders prior to their scheduled terms under certain circumstances. Any sales in the public market of the common stock issuable upon such conversion could adversely affect prevailing market prices of our common stock. In addition, the existence of the 2026 Convertible Notes may encourage short selling by market participants because the conversion of the 2026 Convertible Notes could be used to satisfy short positions, or anticipated conversion of the 2026 Convertible Notes into shares of our common stock could depress the price of our common stock. Any of these events may dilute the ownership interests of our stockholders, reduce our earnings 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 3. LEGAL PROCEEDINGS

The information required by this item is included in Note 16—Contingencies to the 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 12, 2021, our common stock was held by 158 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 repurchase activity for each period presented:

Period	Total Number of Shares Purchased	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
October 1, 2020 - October 31, 2020 (1)	13,550	$ 3.62	—	$ —
November 1, 2020 - November 30, 2020	—	—	—	—
December 1, 2020 - December 31, 2020	—	—	—	—
Total	13,550	$ 3.62	—	$ —

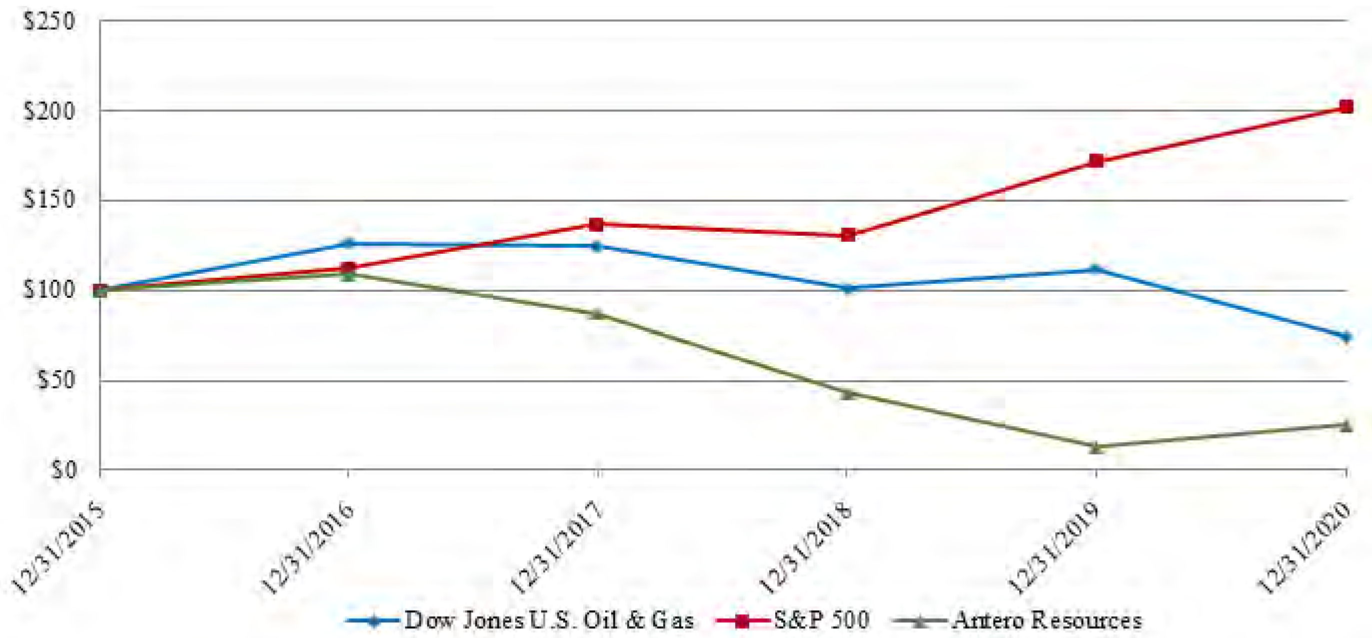
(1) The total number of shares purchased includes 13,550 shares repurchased in October 2020, representing shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of restricted stock and restricted stock units held by our employees.

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) indentures related to our 5.125% senior notes due 2022, 5.625% senior notes due 2023, 5.00% senior notes due 2025, 8.375% senior notes due 2026, 7.625% senior notes due 2029 and 4.25% convertible senior notes due 2026 and (iv) the Credit Facility. We have not paid or declared any dividends on our common stock. The 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, 2015 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. SELECTED FINANCIAL DATA

The following table shows our selected historical consolidated financial data, for the periods ended and as of the dates indicated, for Antero Resources Corporation and its consolidated subsidiaries, including Antero Midstream Partners through March 12, 2019. Effective March 13, 2019, we no longer consolidate Antero Midstream Partners and account for our interest in Antero Midstream using the equity method of accounting. See Note 6—Equity Method Investments to the consolidated financial statements for further discussion of our equity method investments.

The selected statement of operations data and statement of cash flows data for the years ended December 31, 2018, 2019 and 2020 and the balance sheet data as of December 31, 2019 and 2020 are derived from our audited consolidated financial statements included in Item 8 of this Annual Report on Form 10-K. The selected statement of operations data and statement of cash flows data for the years ended December 31, 2016 and 2017 and the balance sheet data as of December 31, 2016, 2017 and 2018 are derived from our audited consolidated financial statements not included in Item 8 of this Annual Report on Form 10-K.

The balance sheet data for the year ended December 31, 2016 has been recast to present the effects of the adoption of Accounting Standards Update ("ASU") No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, in 2016, which requires that debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that liability.

Our historical results of operations for the years ended December 31, 2016 and 2017 reflect a U.S. federal corporate tax rate of 35%. Effective January 1, 2018, the U.S. federal corporate tax rate was reduced from 35% to 21%. Accordingly, our historical results of operations prior to this change reflect a higher U.S. federal corporate tax rate when compared to subsequent period financial results.

The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K.

(in thousands, except per share amounts)	Year Ended December 31, 2016	2017	2018	2019	2020
Statement of operations data:					
Operating revenues and other:					
Natural gas sales	$ 1,260,750	1,769,284	2,287,939	2,247,162	1,809,952
NGLs sales	432,992	870,441	1,177,777	1,219,162	1,161,683
Oil sales	61,319	108,195	187,178	177,549	112,270
Commodity derivative fair value gains (losses)	(514,181)	658,283	(87,594)	463,972	79,918
Gathering, compression, and water handling and treatment	12,961	12,720	21,344	4,478	—
Marketing	393,049	258,045	458,901	292,207	310,572
Marketing derivative fair value gains (losses)	—	(21,394)	94,081	—	—
Amortization of deferred revenue, VPP	—	—	—	—	14,507
Gain on sale of assets	97,635	—	—	—	—
Other income	—	—	—	4,160	2,797
Total operating revenues and other	1,744,525	3,655,574	4,139,626	4,408,690	3,491,699
Operating expenses:					
Lease operating	50,090	89,057	136,153	145,720	98,865
Gathering, compression, processing, and transportation	882,838	1,095,639	1,339,358	2,146,647	2,530,838
Production and ad valorem taxes	66,588	94,521	126,474	125,142	106,775
Marketing	499,343	366,281	686,055	549,814	469,404
Exploration	6,862	8,538	4,958	884	1,083
Impairment of oil and gas properties	162,935	159,598	549,437	1,300,444	223,770
Impairment of midstream assets	—	23,431	9,658	14,782	—
Depletion, depreciation, and amortization	809,873	824,610	972,465	914,867	861,870
Loss on sale of assets			—	951	348
Accretion of asset retirement obligations	2,473	2,610	2,819	3,762	3,421
General and administrative (including equity-based compensation expense of $102,421, $103,445, $70,413, $23,559 and $23,317 in 2016, 2017, 2018, 2019 and 2020, respectively)	239,324	251,196	240,344	178,696	134,482
Contract termination and rig stacking	—	—	—	14,026	14,290
Total operating expenses	2,720,326	2,915,481	4,067,721	5,395,735	4,445,146
Operating income (loss)	(975,801)	740,093	71,905	(987,045)	(953,447)
Other Expenses:					
Water earnout	—	—	—	125,000	—
Loss on the sale of equity method investment shares	—	—	—	(108,745)	—
Equity in earnings (loss) of unconsolidated affiliate	485	20,194	40,280	(143,216)	(62,660)
Impairment of equity method investment	—	—	—	(467,590)	(610,632)
Gain on deconsolidation of Antero Midstream Partners LP	—	—	—	1,406,042	—
Transaction expense	—	—	—	—	(7,244)
Interest expense, net	(253,552)	(268,701)	(286,743)	(228,111)	(199,872)
Gain (loss) on early extinguishment of debt	(16,956)	(1,500)	—	36,419	175,962
Total other income (expenses)	(270,023)	(250,007)	(246,463)	619,799	(704,446)
Income (loss) before income taxes and discontinued operations	(1,245,824)	490,086	(174,558)	(367,246)	(1,657,893)
Income tax benefit	496,376	295,051	128,857	74,110	397,482
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(749,448)	785,137	(45,701)	(293,136)	(1,260,411)
Net income and comprehensive income attributable to noncontrolling interest	99,368	170,067	351,816	46,993	7,486
Net income (loss) attributable to Antero Resources Corporation	$ (848,816)	615,070	(397,517)	(340,129)	(1,267,897)
Earnings (loss) per common share—basic	$ (2.88)	1.95	(1.26)	(1.11)	(4.65)
Earnings (loss) per common share—dilutive	$ (2.88)	1.94	(1.26)	(1.11)	(4.65)

(in thousands)	Year Ended December 31, 2016	2017	2018	2019	2020
Balance sheet data (at period end):					
Cash and cash equivalents	$ 31,610	28,441	—	—	—
Other current assets	370,977	804,646	806,613	922,885	574,139
Total current assets	402,587	833,087	806,613	922,885	574,139
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,331,173	2,266,673	1,767,600	1,368,854	1,175,178
Producing properties	9,549,671	11,096,462	12,705,672	11,859,817	12,260,713
Water handling and treatment systems	744,682	946,670	1,013,818	5,802	5,802
Gathering systems and facilities	1,723,768	2,050,490	2,470,708	—	—
Other property and equipment	41,231	57,429	65,842	71,895	74,361
	14,390,525	16,417,724	18,023,640	13,306,368	13,516,054
Less accumulated depletion, depreciation, and amortization	(2,363,778)	(3,182,171)	(4,153,725)	(3,327,629)	(3,869,116)
Property and equipment, net	12,026,747	13,235,553	13,869,915	9,978,739	9,646,938
Other assets	1,826,216	1,192,850	842,936	4,295,945	2,929,768
Total assets	$ 14,255,550	15,261,490	15,519,464	15,197,569	13,150,845
Current liabilities	$ 817,388	762,096	853,540	1,040,139	983,054
Long-term indebtedness	4,703,973	4,800,090	5,461,688	3,758,868	3,001,593
Other long-term liabilities	1,005,611	823,168	716,759	3,427,819	3,075,927
Total equity	7,728,578	8,876,136	8,487,477	6,970,743	6,090,271
Total liabilities and equity	$ 14,255,550	15,261,490	15,519,464	15,197,569	13,150,845
Other financial data:					
Net cash provided by operating activities	$ 1,241,256	2,006,291	2,081,987	1,103,458	735,640
Net cash used in investing activities	$ (2,395,138)	(2,461,630)	(2,350,724)	(1,041,490)	(530,061)
Net cash provided by (used in) financing activities	$ 1,162,019	452,170	240,296	557,564	(205,579)
Capital expenditures	$ 2,495,429	2,216,753	2,210,586	1,422,155	874,357
Adjusted EBITDAX	$ 1,384,442	1,244,394	1,717,120	1,247,671	1,002,016

Adjusted EBITDAX is a non-GAAP financial measure that we define as net income (loss), including noncontrolling interests, before interest expense, interest income, gains or losses from commodity derivatives and marketing derivatives, amortization of deferred revenue but including net cash receipts or payments on derivative instruments included in derivative gains or losses other than proceeds from derivative monetizations, income taxes, impairments, depletion, depreciation, amortization, and accretion, exploration expense, equity-based compensation, gain or loss on early extinguishment of debt, contract termination and rig stacking costs, loss on sale of the equity method investment shares, equity in earnings or loss of unconsolidated affiliates, water earnout, simplification transaction fees, gain or loss on sale of assets, Antero Midstream Partners related adjustments and Martica related adjustments.

Through March 12, 2019, the financial results of Antero Midstream Partners were included in our consolidated results. Effective March 13, 2019, we no longer consolidate Antero Midstream Partners and account for our interest in Antero Midstream using the equity method of accounting. See Note 6—Equity Method Investments to the consolidated financial statements for more information on our equity method investments. Adjusted EBITDAX includes distributions received with respect to limited partner interests in Antero Midstream Partners common units through March 12, 2019.

Adjusted EBITDAX as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income or loss, net income or loss, cash flows provided by operating, investing, and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDAX provides no information regarding our capital structure, borrowings, interest costs, capital expenditures, working capital movement, or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure operating performance without regard to items excluded from the calculation of such term, which may vary substantially from company to company depending upon accounting methods and the book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital and legal structure from our operating structure;

- is used by our management team for various purposes, including as a measure of our operating performance, in presentations to our Board of Directors, and as a basis for strategic planning and forecasting; and

- is used by our Board of Directors as a performance measure in determining executive compensation.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effects of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies, and the different methods of calculating Adjusted EBITDAX reported by different companies.

The following table represents a reconciliation of our net income (loss), including noncontrolling interest, to Adjusted EBITDAX and a reconciliation of our Adjusted EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case, for the periods presented. Adjusted EBITDAX also excludes the results of Antero Midstream Partners to provide comparability with the current structure of Antero Resources because effective March 13, 2019, we no longer consolidate Antero Midstream Partners' results. These adjustments are disclosed in the table below as Antero Midstream Partners related adjustments.

(in thousands)		Year ended December 31, 2016	2017	2018	2019	2020
Reconciliation of net income (loss) to Adjusted EBITDAX:						
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$	(848,816)	615,070	(397,517)	(340,129)	(1,267,897)
Net income (loss) and comprehensive income (loss) attributable to noncontrolling interests		99,368	170,067	351,816	46,993	7,486
Unrealized commodity derivative gains (losses)		1,517,264	305,563	701,071	(138,882)	725,011
Gains (losses) on settled marketing derivatives		—	21,394	(94,081)	—	—
Marketing derivative fair value gains		—	—	72,687	—	—
Proceeds from derivative monetizations		—	(749,906)	(370,365)	—	(9,007)
Amortization of deferred revenue, VPP		—	—	—	—	(14,507)
(Gain) loss on sale of assets		(97,635)	—	—	951	348
Gain on deconsolidation of Antero Midstream Partners LP		—	—	—	(1,406,042)	—
Interest expense, net		253,552	268,701	286,743	228,111	199,872
(Gain) loss on early extinguishment of debt		16,956	1,500	—	(36,419)	(175,962)
Provision for income tax benefit		(496,376)	(295,051)	(128,857)	(74,110)	(397,482)
Depletion, depreciation, amortization, and accretion		812,346	827,220	975,284	918,629	865,291
Impairment of oil and gas properties		162,935	159,598	549,437	1,300,444	223,770
Impairment of midstream assets		—	23,431	9,658	14,782	—
Impairment of equity method investment		—	—	—	467,590	610,632
Exploration expense		6,862	8,538	4,958	884	1,083
Equity-based compensation expense		102,421	103,445	70,413	23,559	23,317
Equity in (earnings) loss of unconsolidated affiliates		(485)	(20,194)	(40,280)	143,216	62,660
Distributions/dividends from unconsolidated affiliates		7,702	20,195	46,415	157,956	171,022
State franchise taxes		50	—	—	—	—
Loss on the sale of equity method investment shares		—	—	—	108,745	—
Contract termination and rig stacking		—	—	—	14,026	14,290
Water earnout		—	—	—	(125,000)	—
Simplification transaction fees		—	—	—	15,482	—
Transaction expense		—	—	—	—	7,244
		1,536,144	1,459,571	2,037,382	1,320,786	1,047,171
Antero Midstream Partners related adjustments [(1)]		(151,702)	(215,177)	(320,262)	(73,115)	—
Martica related adjustments [(2)]		—	—	—	—	(45,155)
Adjusted EBITDAX	$	1,384,442	1,244,394	1,717,120	1,247,671	1,002,016
Reconciliation of our Adjusted EBITDAX to net cash provided by operating activities:						
Adjusted EBITDAX	$	1,384,442	1,244,394	1,717,120	1,247,671	1,002,016
Antero Midstream Partners related adjustments [(1)]		151,702	215,177	320,262	73,115	—
Martica related adjustments [(2)]		—	—	—	—	45,155
Interest expense, net		(253,552)	(268,701)	(286,743)	(228,111)	(199,872)
Exploration expense		(6,862)	(8,538)	(4,958)	(884)	(1,083)
Changes in current assets and liabilities		(32,920)	76,035	(25,423)	35,542	(109,047)
State franchise taxes		(50)	—	—	—	—
Simplification transaction fees		—	—	—	(15,482)	—
Transaction expense		—	—	—	—	(7,244)
Proceeds from derivative monetizations		—	749,906	370,365	—	9,007
Premium paid on derivative contracts		—	—	(13,318)	—	—
Other items		(1,504)	(1,982)	4,682	(8,393)	(3,292)
Net cash provided by operating activities	$	1,241,256	2,006,291	2,081,987	1,103,458	735,640

(1) Amounts reflected are net of any elimination adjustments for intercompany activity and include activity related to Antero Midstream Partners through March 12, 2019. Effective March 13, 2019, Antero accounts for its unconsolidated investment in Antero Midstream Corporation using the equity method of accounting. See Note 6—Equity Method Investments to the consolidated financial statements for further discussion on equity method investments.

(2) Adjustments reflect noncontrolling interests in Martica not otherwise adjusted in amounts above.

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, including the COVID-19 pandemic, 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.

In this section, references to "Antero," the "Company," "we," "us," and "our" refer to Antero Resources Corporation and its subsidiaries, unless otherwise indicated or the context otherwise requires.

Our Company

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

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Appalachian Basin. As of December 31, 2020, we held approximately 515,000 net acres in the Appalachian Basin. In addition, we estimate that approximately 174,000 net acres of our leasehold may be prospective for the slightly shallower Upper Devonian Shale.

As of December 31, 2020, our estimated proved reserves were approximately 17.6 Tcfe, consisting of 10.0 Tcf of natural gas, 745 MMBbl of assumed recovered ethane, 491 MMBbl of C3+ NGLs, and 32 MMBbl of oil. This represents a 7% decrease in estimated proved reserves from December 31, 2019. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2020, we had approximately 2,133 potential horizontal well locations on our existing leasehold acreage that were classified as proved, probable and possible.

We operate in the following industry segments: (i) the exploration, development, and production of natural gas, NGLs, and oil; (ii) marketing of excess firm transportation capacity; and (iii) midstream services through our equity method investment in Antero Midstream Corporation. As described below and elsewhere in this Annual Report on Form 10-K, effective March 13, 2019, we no longer consolidate the results of Antero Midstream Partners. All of our operations are conducted in the United States.

Recent Developments and Highlights

COVID-19 Pandemic

In March 2020, the World Health Organization declared the COVID-19 outbreak a pandemic. Governments have tried to slow the spread of the virus by imposing social distancing guidelines, travel restrictions and stay-at-home orders, which have caused a significant decrease in activity in the global economy and the demand for oil and, to a lesser extent, natural gas and NGLs. Also, in March 2020, Saudi Arabia and Russia failed to agree to cut production of oil along with the Organization of the Petroleum Exporting Countries ("OPEC"), and Saudi Arabia significantly reduced the price at which it sells oil and announced plans to increase production, which contributed to a sharp drop in the price of oil. While OPEC, Russia and other allied producers reached an agreement in April 2020 to reduce production, oil prices have remained low. The imbalance between the supply of and demand for oil, as well as the uncertainty around the extent and timing of an economic recovery, have caused extreme market volatility and a substantial adverse effect on commodity prices.

As a producer of natural gas, NGLs and oil, we are recognized as an essential business under various federal, state and local regulations related to the COVID-19 pandemic. We have continued to operate as permitted under these regulations while taking steps to protect the health and safety of our employees and contract workers. We have implemented protocols to reduce the risk of an outbreak within our field operations, and these protocols have not reduced production or efficiency in a significant manner. A substantial portion of our non-field level employees continue to operate in remote work from home arrangements, and we have been able to maintain a consistent level of effectiveness through these arrangements, including maintaining our day-to-day operations, our financial reporting systems and our internal control over financial reporting.

Our natural gas, NGLs and oil producing properties are located in the liquids-rich Appalachian Basin. Although the decline in oil prices has negatively impacted our oil revenue, oil sales represented approximately 3% of our total revenue for the year ended December 31, 2020. While natural gas prices also declined during the first half of 2020, benchmark Henry Hub prices recovered during the third quarter and averaged $2.32/Mcf in the last half of 2020. Similarly, C3+ NGL prices also improved during the second half of 2020 as gasoline demand increased, supporting prices for normal butane (nC4), isobutane (iC4), and pentane (C5), all of which are used for gasoline. The COVID-19 pandemic reduced gasoline demand, which forced C5 prices below propane prices for much of April 2020 to under $0.40 per gallon, has since rebounded with benchmark C5 price in January 2021 in the range of $1.05 to $1.25 per gallon.

In addition, we have hedged through fixed price contracts the sale of 2.2 Bcf per day of natural gas at a weighted average price of $2.77 per MMBtu in 2021. Our hedges cover a substantial majority of our expected natural gas production in 2021. We also have fixed priced contracts for the sale of 19,000 barrels per day of ethane at a weighted average price of $0.20 per gallon and 3,000 barrels per day of oil at a weighted average price of $55.16 per barrel for 2021. All of our hedges are financial hedges and do not have physical delivery requirements. As such, any decreases in anticipated production, whether as a result of decreased development activity, shut-ins, or through transactions under our asset sale plan, will not impact our ability to realize the benefits of the hedges.

Our natural gas and NGLs are primarily used in manufacturing, power generation and heating rather than transportation. While we have seen a decrease in the overall demand for these products, demand for natural gas and NGLs has not declined as much as demand for oil, and there has not been as substantial an oversupply of natural gas and NGLs as there has been of oil. Furthermore, the decrease in demand for oil has significantly reduced the number of rigs drilling for oil in the continental U.S. and, as a result, estimates of future gas supply associated with oil production have declined. Additionally, the restart of economic activity in Asia and Europe, coupled with lower LPG production from refineries in the U.S., Europe, and Asia during the second quarter, provided support for international LPG prices relative to oil. Further, reductions in OPEC+ and North American oil production and the associated NGL volumes are expected to have a supportive effect on propane and butane prices into 2021.

During the fourth quarter of 2020, we shipped 43% of our total C3+ NGL net production on Mariner East 2 for export and realized a $0.11 per gallon premium to Mont Belvieu pricing on these volumes at Marcus Hook, PA. We sold the remaining 57% of C3+ NGL net production at a $0.06 per gallon discount to Mont Belvieu pricing at Hopedale, OH. We expect to sell at least 48% of our C3+ NGL full-year production in 2021 at Marcus Hook for export at a premium to Mont Belvieu.

Condensate differentials to WTI were approximately $12/Bbl during the fourth quarter. Pre-hedge oil realizations were negatively impacted during the second quarter and beginning of the third quarter as Antero sold volumes at a material discount to WTI in order to keep from shutting in production volumes. This period of weak condensate demand driven by the pandemic coincided with an active well completion period for Antero that brought on large condensate volumes. The negative impact from wider oil differentials was more than offset by the benefit of maintaining full natural gas and NGL volumes through this period. Antero expects its full year 2021 realized oil price differential to be at the high end of the $9.00/Bbl to $11.00/Bbl range, as the differential normalized during the fourth quarter of 2020.

Our supply chain also has not experienced any significant interruptions. The lack of a market or available storage for any one NGL product or oil could result in our having to delay or discontinue well completions and commercial production or shut in production for other products because we cannot curtail the production of individual products in a meaningful way without reducing production of other products. Potential impacts of these constraints may include partial shut-in of production, although we are not able to determine the extent of shut-ins or for how long they may last. However, because some of our wells produce rich gas, which is processed, and some produce dry gas, which does not require processing, we can change the mix of products that we produce and wells that we complete to adjust our production to address takeaway capacity constraints for certain products. For example, we can shut-in rich gas wells and still produce from our dry gas wells if processing or storage capacity of NGL products becomes further limited or constrained. Also, prior to the COVID-19 pandemic, we had developed a diverse set of buyers and destinations, as well as in-field and off-site storage capacity for our condensate volumes, and such capacity is still largely available to us.

In addition, as discussed in "—Capital Resources and Liquidity—2020 Capital Spending and 2021 Capital Budget" below, we announced a 21% reduction in our drilling and completion capital budget for 2021 compared to 2020. During the fourth quarter, our ongoing emphasis on completion efficiencies and drilling longer laterals resulted in material improvements in well costs. Well costs averaged approximately $680 per lateral foot during the fourth quarter, benefiting from these efficiency improvements and lateral lengths that averaged over 15,000 feet. Well costs were approximately $690 per foot when normalized for a 12,000 foot lateral length. We expect well costs to average $660 per foot during the first quarter of 2021, based on a 12,000 foot lateral. We continue to monitor our five-year drilling plan and will make further revisions as appropriate.

During the first quarter of 2020 and the two preceding quarters, we recognized various impairment charges related to the decline in commodity prices and the value of our investment in Antero Midstream Corporation. At this time, we do not anticipate any further impairment charges in our equity method investment in Antero Midstream Corporation because the value of our equity method investment has increased since the end of the first quarter of 2020. Additional impairment charges related to our assets may occur if we experience disruptions in production, additional or sustained declines in the forward commodity price strip from December 31, 2020, unresolved storage capacity restraints or other consequences caused by the COVID-19 pandemic.

In October 2020, the borrowing base supporting our Credit Facility was subject to its semi-annual redetermination and was re-affirmed at $2.85 billion. Lender commitments remained unchanged at $2.64 billion, providing us with a consistent amount of available borrowings. Our next semi-annual borrowing base redetermination is in April 2021, which could impact our available borrowings and liquidity.

In addition, our borrowing capacity is directly impacted by the amount of financial assurance we are required to provide in the form of letters of credit to third parties, primarily pipeline capacity providers. The amount of financial assurance we must provide has not increased during the COVID-19 pandemic and, thus far, we have not experienced any losses due to counterparty risk. However, our ability to limit any additional financial assurance we are required to provide, as well as to protect ourselves from the counterparty risk of our financial hedges, may be limited in the future. Since the onset of the COVID-19 pandemic, we have timely serviced our debt and other obligations, and we have not implemented or requested any concessions or materially modified the terms of any agreements.

The COVID-19 pandemic, commodity market volatility and resulting financial market instability are variables beyond our control and may adversely impact our generation of funds from operating cash flows, distributions from unconsolidated affiliates, available borrowings under our Credit Facility and our ability to access the capital markets.

Financing Highlights

Debt Repurchase Program

During the year ended December 31, 2020, we repurchased $1.4 billion principal amount of our senior notes through open market repurchases, tender offers and redemptions at a weighted average discount of 13%. We recognized a gain of $176 million for the year ended December 31, 2020 on the early extinguishment of the debt repurchased. As a result, our 5.375% senior notes due November 1, 2021 (the "2021 Notes") were fully retired as of November 30, 2020. Additionally, we fully redeemed our 5.125% senior notes due December 1, 2022 (the "2022 Notes") at par, plus accrued and unpaid interest in the first quarter of 2021. See Note 8—Long-Term Debt to the consolidated financial statements for more information.

Asset Sales Program

On June 15, 2020, we announced the consummation of a transaction with an affiliate of Sixth Street Partners, LLC ("Sixth Street") relating to certain overriding royalty interests across our existing asset base (the "ORRIs"). In connection with the transaction, we contributed the ORRIs to a newly formed subsidiary, Martica Holdings LLC ("Martica"). At the initial closing, 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 are achieved in the third quarter of 2020 and first quarter of 2021. All cash contributed by Sixth Street was distributed to us. We met the production threshold related to the third quarter of 2020 and received a $51 million cash distribution during the year ended December 31, 2020. See Note 4—Transactions to the consolidated financial statements for more information.

On August 10, 2020, we completed a volumetric production payment transaction and received net proceeds of approximately $216 million (the "VPP"). In connection with the VPP, we entered into a purchase and sale agreement, together with a conveyance agreement and production and marketing agreement, with J.P. Morgan Ventures Energy Corporation ("JPM-VEC") to convey, effective July 1, 2020, an overriding royalty interest in dry gas producing properties in West Virginia (the "VPP Properties") equal to

136,589,000 MMBtu over the expected seven-year term of the VPP. See Note 4—Transactions to the consolidated financial statements for more information.

On February 17, 2021, we announced the formation of a drilling partnership with QL Capital Partners ("QL"), an affiliate of Quantum Energy Partners. Under the terms of the arrangement, QL will fund 20% of total development capital spending in 2021 and is expected to fund between 15% and 20% of total development capital spending on an annual basis from 2022 through 2024. All of the wells spud during each calendar year period will be a separate annual tranche. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche will be for our account.

For each tranche other than 2021, we will propose a capital budget and estimated internal rate of return ("IRR") for all wells to be spud during the year and, subject to the mutual agreement of the parties that the estimated IRR for each tranche exceeds a specified return, QL will be obligated to participate in such tranche. For each annual tranche in which QL participates, QL will receive a proportionate working interest percentage in each well spud in such tranche. If we present a capital budget for an annual tranche with an estimated IRR equal to or exceeding a specified return that QL in good faith believes is less than such specified return and QL elects not to participate, we will not be obligated to offer QL the opportunity to participate in subsequent tranches. No earlier than December 31 following the expiration of each tranche year, we will calculate the tranche IRR for such tranche year and, if the tranche IRR exceeds certain specified returns, we will receive a carry in the form of a one-time payment from QL for such annual tranche.

Issuance of Convertible Senior Notes and Senior Notes

On August 21, 2020, we issued $250 million in aggregate principal amount of 4.25% senior unsecured convertible notes (the "2026 Convertible Notes"). On September 2, 2020, we issued an additional $37.5 million of the 2026 Convertible Notes. The initial conversion rate is 230.2026 shares of our common stock per $1,000 principal amount of 2026 Convertible Notes, subject to adjustment upon the occurrence of specified events. Please see "—Debt Agreements and Contractual Obligations—Senior Unsecured Notes" below and Note 8—Long-Term Debt to the consolidated financial statements for more information.

On January 4, 2021, we issued $500 million of 8.375% senior notes due July 15, 2026 (the "2026 Notes") at par. On January 26, 2021, we issued $700 million of 7.625% senior notes due February 1, 2029 (the "2029 Notes") at par. The 2026 Notes and 2029 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2026 Notes and 2029 Notes rank pari passu to our other outstanding senior notes. The 2026 Notes and 2029 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by our wholly owned subsidiaries and certain of our future restricted subsidiaries. Please see "—Debt Agreements and Contractual Obligations—Senior Unsecured Notes" below and Note 8—Long-Term Debt to the consolidated financial statements for more information.

Convertible Notes Equitization

On January 12, 2021, we completed a registered direct offering (the "Share Offering") of an aggregate of 31.4 million shares of our common stock at a price of $6.35 per share to certain holders of our 2026 Convertible Notes. We used the proceeds from the Share Offering and approximately $63 million of borrowings under the Credit Facility to repurchase from such holders $150 million aggregate principal amount of the 2026 Convertible Notes in privately negotiated transactions (the "Convertible Note Repurchase," and, collectively with the Share Offering, the "Equitization Transactions"). See Note 8—Long-Term Debt to the consolidated financial statements for more information.

Share Repurchase Program

Our board-approved share repurchase program expired on March 31, 2020. Prior to the program's expiration, we repurchased and retired 28,193,237 common shares at a weighted average price per share of $1.54 for approximately $43 million during the first quarter of 2020.

Sources of Our Revenues

- *Natural gas, NGL 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 2020, our production revenues were comprised of approximately 59% from the sale of natural gas and 41% 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.* To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our production. We enter into primarily fixed price natural gas, NGLs, and oil swap contracts for natural gas in which we receive or pay the difference between a fixed price and the variable market price received, as well as basis swap contracts that hedge the difference between the New York Mercantile Exchange ("NYMEX") index price and a local index price. At the end of each accounting period, we estimate the fair value of these swaps 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, water handling and treatment revenues.* Gathering, compression, water handling and treatment revenues are derived from our ownership interest in Antero Midstream Partners through March 12, 2019 and Antero Midstream thereafter.

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, 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 costs to purchase services from Antero Midstream and fees paid to other third parties who operate low- and high-pressure gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced 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.

- *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 (not hedged prices) 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 expense.* These are primarily costs related to unsuccessful leasing efforts, as well as geological and geophysical costs, including seismic costs, and costs of unsuccessful exploratory dry holes.

- *Impairment of oil and gas properties.* These costs include impairment and costs associated with leases expirations, impairment of design and initial costs related to pads that are no longer planned to be placed into service, and impairment of proved properties due to lower future commodity prices. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks and future plans to develop the acreage. We also 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.

- *Depletion, depreciation, and amortization.* 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 10—Equity-Based Compensation and Retention Awards to the consolidated financial statements for more information.

- *Interest expense.* We finance a portion of our capital expenditures, working capital requirements, and acquisitions with borrowings under the Credit Facility, which has a variable rate of interest based on LIBOR or the prime rate. 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, 2020, we had a fixed interest rate of 5.125% on our 2022 Notes having a principal balance of $661 million, a fixed interest rate of 5.625% on our 2023 Notes having a principal balance of $574 million, a fixed interest rate of 5.00% on our 2025 Notes having a principal balance of $590 million, and a fixed interest rate of 4.25% on our 2026 Convertible Notes having a principal balance of $287.5 million. See Note 8—Long-Term Debt to the consolidated financial statements for more information.

- *Income tax expense.* We are subject to state and federal income taxes but are currently not in a cash tax paying position with respect to federal income taxes. The difference between our financial statement income tax expense and our federal income tax liability is primarily due to the differences in the tax and financial statement treatment of oil and gas properties, the effects of noncontrolling interests and the deferral of unsettled commodity derivative gains for tax purposes until they are settled. We do pay some state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We have recorded deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets. See Note 14—Income Taxes to the consolidated financial statements for more information.

Results of Operations

We have three operating segments: (1) the exploration, development and production of natural gas, NGLs, and oil; (2) marketing and utilization of excess firm transportation capacity gathering and processing; and (3) midstream services through our equity method investment in Antero Midstream Corporation. Revenues from Antero Midstream's operations were primarily derived from intersegment transactions for services provided to our exploration and production operations by Antero Midstream Partners. All intersegment transactions were eliminated upon consolidation, including revenues from water handling and treatment services provided by Antero Midstream Partners, which we capitalized as proved property development costs. Through March 12, 2019, we included the results of Antero Midstream Partners in our consolidated financial statements. Effective March 13, 2019, we no longer consolidate the results of Antero Midstream Partners in our results; however, our segment disclosures include the segments of our unconsolidated affiliates, due to their significance to our operations. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for further discussion on the simplification transactions and Note 18—Segment Information to the consolidated financial statements for disclosures on our reportable segments. 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.

Year Ended December 31, 2019 Compared to Year Ended December 31, 2020

The operating results of our reportable segments were as follows for the years ended December 31, 2019 and 2020 (in thousands):

	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream Corporation [(1)]	Elimination of Intersegment Transactions and Unconsolidated Affiliates	Consolidated Total
Year Ended December 31, 2019					
Revenue and other:					
Natural gas sales	$ 2,247,162	—	—	—	2,247,162
Natural gas liquids sales	1,219,162	—	—	—	1,219,162
Oil sales	177,549	—	—	—	177,549
Commodity derivative fair value gains	463,972	—	—	—	463,972
Gathering, compression, water handling and treatment	—	—	849,598	(845,120)	4,478
Marketing	—	292,207	—	—	292,207
Other income (loss)	5,812	—	(57,010)	55,358	4,160
Total	$ 4,113,657	292,207	792,588	(789,762)	4,408,690
Operating expenses:					
Lease operating	146,990	—	162,376	(163,646)	145,720
Gathering and compression	825,777	—	41,013	(151,465)	715,325
Processing	774,280	—	—	—	774,280
Transportation	657,042	—	—	—	657,042
Production and ad valorem taxes	124,202	—	3,830	(2,890)	125,142
Marketing	—	549,814	—	—	549,814
Exploration	884	—	—	—	884
Impairment of oil and gas properties	1,300,444	—	—	—	1,300,444
Impairment of midstream assets	—	—	776,832	(762,050)	14,782
Depletion, depreciation, and amortization	893,161	—	95,526	(73,820)	914,867
Accretion of asset retirement obligations	3,699	—	187	(124)	3,762
General and administrative (excluding equity-based compensation)	139,320	—	44,596	(28,779)	155,137
Equity-based compensation	21,082	—	73,517	(71,040)	23,559
Change in fair value of contingent acquisition consideration	—	—	8,076	(8,076)	—
Contract termination and rig stacking	14,026	—	—	—	14,026
Loss on sale of assets	951	—	—	—	951
Total	4,901,858	549,814	1,205,953	(1,261,890)	5,395,735
Operating income (loss)	$ (788,201)	(257,607)	(413,365)	472,128	(987,045)
Equity in earnings of unconsolidated affiliates	$ —	—	51,315	(194,531)	(143,216)

(1) Includes the consolidated results of Antero Midstream Partners through March 12, 2019 and results of the Company's equity method investment in Antero Midstream Corporation effective March 13, 2019.

	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream Corporation	Elimination of Intersegment Transactions and Unconsolidated Affiliates	Consolidated Total
Year Ended December 31, 2020					
Revenue and other:					
Natural gas sales	$ 1,809,952	—	—	—	1,809,952
Natural gas liquids sales	1,161,683	—	—	—	1,161,683
Oil sales	112,270	—	—	—	112,270
Commodity derivative fair value gains	79,918	—	—	—	79,918
Gathering, compression, water handling and treatment	—	—	971,391	(971,391)	—
Marketing	—	310,572	—	—	310,572
Amortization of deferred revenue, VPP	14,507	—	—	—	14,507
Other income	2,797	—	(70,672)	70,672	2,797
Total	$ 3,181,127	310,572	900,719	(900,719)	3,491,699
Operating expenses:					
Lease operating	$ 98,865	—	—	—	98,865
Gathering and compression	834,758	—	165,386	(165,386)	834,758
Processing	909,038	—	—	—	909,038
Transportation	787,042	—	—	—	787,042
Production and ad valorem taxes	106,775	—	—	—	106,775
Marketing	—	469,404	—	—	469,404
Exploration	1,083	—	—	—	1,083
Impairment of oil and gas properties	223,770	—	—	—	223,770
Impairment of midstream assets	—	—	673,640	(673,640)	—
Depletion, depreciation, and amortization	861,870	—	108,790	(108,790)	861,870
Accretion of asset retirement obligations	3,421	—	180	(180)	3,421
General and administrative (excluding equity-based compensation)	111,165	—	39,435	(39,435)	111,165
Equity-based compensation	23,317	—	12,778	(12,778)	23,317
Contract termination and rig stacking and other expenses	14,290	—	15,219	(15,219)	14,290
Loss on sale of assets	348	—	2,929	(2,929)	348
Total	3,975,742	469,404	1,018,357	(1,018,357)	4,445,146
Operating loss	$ (794,615)	(158,832)	(117,638)	117,638	(953,447)
Equity in earnings (loss) of unconsolidated affiliates	$ (62,660)	—	86,430	(86,430)	(62,660)

Exploration and Production Segment Results for the Year Ended December 31, 2019 Compared to the Year Ended December 31, 2020

The following table sets forth selected operating data of the exploration and production segment for the year ended December 31, 2019 compared to the year ended December 31, 2020:

	Years Ended December 31,		Amount of Increase (Decrease)	Percent Change
	2019	2020		
Production data (1) (2):				
Natural gas (Bcf)	822	875	53	6 %
C2 Ethane (MBbl)	15,861	19,709	3,848	24 %
C3+ NGLs (MBbl)	39,445	48,341	8,896	23 %
Oil (MBbl)	3,632	4,412	780	21 %
Combined (Bcfe)	1,175	1,310	135	11 %
Daily combined production (MMcfe/d)	3,220	3,578	358	11 %
Average prices before effects of derivative settlements (3):				
Natural gas (per Mcf)	$ 2.74	2.07	(0.67)	(24)%
C2 Ethane (per Bbl)	$ 7.85	5.77	(2.08)	(26)%
C3+ NGLs (per Bbl)	$ 27.75	21.68	(6.07)	(22)%
Oil (per Bbl)	$ 48.88	25.45	(23.43)	(48)%
Weighted Average Combined (per Mcfe)	$ 3.10	2.35	(0.75)	(24)%
Average realized prices after effects of derivative settlements (3):				
Natural gas (per Mcf)	$ 3.14	2.79	(0.35)	(11)%
C2 Ethane (per Bbl)	$ 7.85	5.65	(2.20)	(28)%
C3+ NGLs (per Bbl)	$ 27.41	23.91	(3.50)	(13)%
Oil (per Bbl)	$ 50.92	38.91	(12.01)	(24)%
Weighted Average Combined (per Mcfe)	$ 3.38	2.96	(0.42)	(12)%
Average costs (per Mcfe):				
Lease operating	$ 0.13	0.08	(0.05)	(38)%
Gathering and compression	$ 0.70	0.64	(0.06)	(9)%
Processing	$ 0.66	0.69	0.03	5 %
Transportation	$ 0.56	0.60	0.04	7 %
Production and ad valorem taxes	$ 0.11	0.08	(0.03)	(27)%
Marketing expense, net	$ 0.22	0.12	(0.10)	(45)%
Depletion, depreciation, amortization, and accretion	$ 0.76	0.66	(0.10)	(13)%
General and administrative (excluding equity-based compensation)	$ 0.12	0.08	(0.04)	(33)%

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

(2) Average prices reflect the before and after effects of our settled commodity derivatives. Our calculation of such after effects includes gains on settlements of commodity derivatives (but does not include proceeds from the derivative monetizations in 2018 and 2020), which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. 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 does not necessarily reflect their relative economic value.

(3) The average realized price for 2019 includes $54 million of the proceeds related to the South Jersey Litigation. See Note 16—Contingencies to the consolidated financial statements for further discussion on the South Jersey Litigation. Excluding the effect of the proceeds of the South Jersey Litigation settlement, the average realized price would have been $2.67 per Mcf.

Natural gas sales. Revenues from sales of natural gas decreased from $2.2 billion, which included litigation proceeds of $54 million, for the year ended December 31, 2019 to $1.8 billion for the year ended December 31, 2020, a decrease of $437 million. Please see Note 16— Contingencies to the consolidated financial statements for more information.

Excluding litigation proceeds, higher natural gas production volumes during the year ended December 31, 2020 accounted for an approximate $143 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 excluding the proceeds from the South Jersey Litigation), and decreases in our prices (excluding the effects of derivative settlements and proceeds from the South Jersey Litigation) accounted for an approximate $526 million decrease in year-over-year gas sales revenue (calculated as the change in the year-to-year average price excluding the proceeds from the South Jersey Litigation times current year production volumes).

NGLs sales. Revenues from sales of NGLs decreased from $1.22 billion for the year ended December 31, 2019 to $1.16 billion for the year ended December 31, 2020, a decrease of $57 million, or 5%. Higher NGLs production volumes accounted for an approximate $277 million increase in year-over-year NGLs sales revenues (calculated as the change in year-to-year volumes times the prior year average price), and changes in our prices, excluding the effects of derivative settlements, accounted for an approximate $334 million decrease in year-over-year NGL sales revenues (calculated as the change in the year-to-year average price times current year production volumes).

Oil sales. Revenues from production of oil decreased from $178 million for the year ended December 31, 2019 to $112 million for the year ended December 31, 2020, a decrease of $66 million. Increased oil production volumes accounted for a $38 million increase in year-over-year oil sales revenues (calculated as the change in year-to-year volumes times the prior year average price), and changes in our prices, excluding the effects of derivative settlements, accounted for an approximate $104 million decrease in year-over-year oil sales revenues (calculated as the change in the year-to-year average price times current year production volumes).

Commodity derivative fair value gains (losses). To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into fixed for variable price swap contracts, basis swap contracts and collar contracts when management believes that favorable future sales prices for our production can be secured. 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. For the years ended December 31, 2019 and 2020, our commodity hedges resulted in derivative fair value gains of $464 million and $80 million, respectively. The commodity derivative fair value gains included $325 million and $795 million of cash proceeds on gains on settled derivatives for the years ended December 31, 2019 and 2020, respectively. Commodity derivative fair value gains (losses) for the year ended December 31, 2020 also include cash proceeds of $9 million related to derivatives that were monetized prior to their contractual settlement dates.

Commodity derivative fair value gains or losses vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled or monetized 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. We expect continued volatility in commodity prices and the related fair value of our derivative instruments in the future.

Amortization of deferred revenue, VPP. The year ended December 31, 2020 includes amortization of $15 million of deferred revenues associated with the VPP, which relate to the production volumes delivered under the terms of the agreement during such period at approximately $1.61 per MMBtu. See Note 4—Transactions to the consolidated financial statements for more information on this transaction.

Other income. Other income remained relatively consistent at $4 million and $3 million for the years ended December 31, 2019 and 2020, respectively.

Lease operating expense. Lease operating expense for the exploration and production segment decreased from $146 million for the year ended December 31, 2019 to $99 million for the year ended December 31, 2020, a decrease of $47 million or 32%. On a per unit basis, lease operating expenses decreased from $0.13 per Mcfe for the year ended December 31, 2019 to $0.08 per Mcfe for the year ended December 31, 2020 primarily due to lower water handling costs resulting from improved operating efficiencies, including the reuse of produced and flowback water in completion operations.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $2.2 billion for the year ended December 31, 2019 to $2.5 billion for the year ended December 31, 2020. This is primarily a result of the 11% increase in production. Gathering and compression costs decreased from $0.70 per Mcfe for the year ended December 31, 2019 to $0.64 per Mcfe for the year ended December 31, 2020 primarily due to lower fuel costs as a result of decreased natural gas prices and $48 million in incentive fee rebates from Antero Midstream Corporation. Processing costs increased from $0.66 per Mcfe to $0.69 per Mcfe for the years ended December 31, 2019 and 2020, respectively, primarily due to increased NGL production in our production mix. Processing costs, however, decreased per NGL barrel year-over-year. Transportation costs increased from $0.56 per Mcfe to $0.60 per Mcfe for the years ended December 31, 2019 and 2020, respectively, primarily due to increased rates on the Rockies Express pipeline, which were effective October 2019 and demand charges for Mountaineer Xpress pipeline.

Production and ad valorem tax expense. Total production and ad valorem taxes decreased from $125 million for the year ended December 31, 2019 to $107 million for the year ended December 31, 2020, a decrease of $18 million or 15%, primarily due to lower commodity prices between periods. On a per Mcfe basis, production and ad valorem taxes decreased from $0.11 per Mcfe for the year ended December 31, 2019 to $0.08 per Mcfe for the year ended December 31, 2020. Production and ad valorem taxes as a percentage of natural gas revenues remained at 6% in each of the years ended December 31, 2019 and 2020.

Exploration expense. Exploration expense representing expenses incurred for unsuccessful lease acquisition efforts remained relatively flat at $1 million for each of the years ended December 31, 2019 and 2020.

Impairment of oil and gas properties. During the year ended December 31, 2019, we recognized an $881 million impairment to write-down our Utica Shale proved properties to fair value because the carrying value of such properties exceeded the estimated undiscounted cash flows based on future strip commodity prices as of September 30, 2019. We also recorded $419 million and $224 million of impairments for the years ended December 31, 2019 and 2020, respectively, related to expiring leases and the design and initial costs related to pads we no longer plan to place into service.

Depletion, depreciation, and amortization expense. DD&A expense decreased from $893 million for the year ended December 31, 2019 to $862 million for the year ended December 31, 2020 for the exploration and production segment, a decrease of $31 million or 4%. DD&A per Mcfe decreased from $0.76 per Mcfe during the year ended December 31, 2019 to $0.66 per Mcfe during the year ended December 31, 2020 due to a reduction in the cost basis of producing properties as a result of the impairments discussed above as well as due to increases in proved reserves between periods.

General and administrative expense. General and administrative expense (excluding equity-based compensation expense) decreased from $139 million for the year ended December 31, 2019 to $111 million for the year ended December 31, 2020, a decrease of $28 million or 20%, primarily due to decreases in employee related expenses in the year ended December 31, 2020 as a result of ongoing cost savings initiatives including lower headcount between periods. We had 547 employees as of December 31, 2019 and 522 employees as of December 31, 2020. On a per unit basis, general and administrative expense excluding equity-based compensation decreased by 33%, from $0.12 per Mcfe during the year ended December 31, 2019 to $0.08 per Mcfe during the year ended December 31, 2020 as a result of higher production volumes and lower overall costs between periods.

Equity-based compensation expense. Noncash equity-based compensation expense increased from $21 million for the year ended December 31, 2019 to $23 million for the year ended December 31, 2020, an increase of $2 million or 8%, primarily due to new awards granted to officers and employees in 2020 partially offset by equity award forfeitures during 2020. When an equity award is forfeited, expense previously recognized for the award is reversed. See Note 10—Equity-Based Compensation and Retention Awards to the consolidated financial statements for more information on equity-based compensation awards.

Contract termination and rig stacking. We incurred contract termination and rig stacking costs of $14 million during each of the years ended December 31, 2019 and 2020. Contract termination and rig stacking costs represent fees incurred upon the delay or cancellation of drilling and completion contracts with third-party contractors in order to align our drilling and completion activity level with our capital budget.

Marketing Segment Results for the Year Ended December 31, 2019 Compared to the Year Ended December 31, 2020

Marketing. 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.

Our net marketing expense decreased from $258 million, or $0.22 per Mcfe, for the year ended December 31, 2019 to $159 million, or $0.12 per Mcfe, for the year ended December 31, 2020. The decrease was driven by higher marketing volumes and the mitigation of some of our excess firm transportation expense.

Marketing revenues increased from $292 million for the year ended December 31, 2019 to $311 million for the year ended December 31, 2020, an increase of $19 million, or 6%, primarily due to increased marketing volumes.

Marketing expenses decreased from $550 million for the year ended December 31, 2019 to $469 million for the year ended December 31, 2020, a decrease of $81 million, or 15%. Marketing expenses include firm transportation costs related to current excess firm capacity as well as the cost of third-party purchased gas and NGLs. Firm transportation costs included in the expenses above were $250 million and $146 million for the years ended December 31, 2019 and 2020, respectively.

Antero Midstream Corporation Segment Results for the Year Ended December 31, 2019 Compared to the Year Ended December 31, 2020

During the period from January 1, 2019 through March 12, 2019, we included the results of Antero Midstream Partners in our consolidated financial statements. Effective March 13, 2019, we no longer consolidate the results of Antero Midstream Partners in our results. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for further discussion on the Transactions. We now account for our interest in Antero Midstream Corporation as an equity method investment.

Antero Midstream Corporation. Revenue from the Antero Midstream Corporation segment increased from $793 million, which included amortization of customer relationships of $57 million, for the year ended December 31, 2019 to $901 million, which included amortization of customer relationships of $71 million, for the year ended December 31, 2020, an increase of $108 million, or 14%. The increase in operating revenue was primarily due to an increase in gathering and compression volumes partially offset by a decrease in fresh water delivery volumes for the year ended December 31, 2020. Total operating expenses related to the segment decreased from $1.2 billion for the year ended December 31, 2019 to $1.0 billion for the year ended December 31, 2020 primarily due to a decrease in total impairments of $88 million period over period.

In addition, Antero Midstream Partners had equity in earnings of unconsolidated affiliates of $51 million and $86 million for the years ended December 31, 2019 and 2020, respectively.

Discussion of Items Not Allocated to Segments for the Year Ended December 31, 2019 Compared to the Year Ended December 31, 2020

Water earnout. In conjunction with the acquisition of the water handling and treatment assets, Antero Midstream agreed to pay us (a) $125 million in cash if Antero Midstream delivered 176 million barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if Antero Midstream delivered 219 million barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. As of December 31, 2019, Antero Midstream had delivered more than the 176 million barrels, which entitled us to $125 million pursuant to clause (a) above, and, as a result, we recognized other income associated with the settlement on the water earnout. The cash proceeds were received in January 2020. As of December 31, 2020, Antero Midstream did not deliver more than 219 million barrels, and, as a result, no additional proceeds were earned with respect to the water earnout.

Impairment of equity method investment. In 2019 and 2020, we determined that events and circumstances indicated that the carrying value of our investment in Antero Midstream Corporation had experienced an other-than-temporary decline and we recorded impairments of $468 million and $611 million, respectively. The fair value of the equity method investment in Antero Midstream Corporation was based on the quoted market share price of Antero Midstream Corporation as of December 31, 2019 and March 31, 2020, respectively.

Interest expense. Our interest expense exclusive of interest expense related to Antero Midstream Partners' indebtedness decreased from $228 million for the year ended December 31, 2019 to $200 million for the year ended December 31, 2020, a decrease of $28 million, or 12%, primarily due to the reduction in debt as a result of our debt repurchases of unsecured senior notes at prices below their stated value, partially offset by interest that accrued on the newly issued 2026 Convertible Notes and higher borrowings on our Credit Facility between periods. Interest expense includes approximately $11 million and $12 million of non-cash amortization of debt issuance costs and debt discounts and premiums for the years ended December 31, 2019 and 2020, respectively.

Income tax benefit. Income tax benefit increased from $74 million, with an effective tax rate of 20%, for the year ended December 31, 2019 to $397 million, with an effective tax rate of 24%, for the year ended December 31, 2020 primarily due to an increased book loss year over year. For the year ended December 31, 2020, our overall effective tax rate was different than the statutory rate of 21% primarily due to the effects of state income taxes, the dividends received deduction and non-deductible equity-based compensation expenses. See Note 14—Income Taxes to our consolidated financial statements more for information regarding our income tax provision for the years ended December 31, 2019 and 2020.

As of December 31, 2019 and 2020, we had U.S. federal and state NOL carryforwards of approximately $2.3 billion and $2.0 billion, respectively. Many of these NOLs expire at various dates between 2032 and 2040 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, 2018 Compared to Year Ended December 31, 2019

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, 2019 for a discussion of the results of operations for the year ended December 31, 2018 compared to the year ended December 31, 2019.

Capital Resources and Liquidity

Overview

Our primary sources of liquidity have been through net cash provided by operating activities including proceeds from derivatives, borrowings under the Credit Facility, issuances of debt and equity securities, distributions/dividends from unconsolidated affiliates and proceeds from our asset sale program. 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 growing our proved reserves and production will be highly dependent on net cash provided by operating activities and the capital resources available to us.

The Credit Facility has a borrowing base of $2.85 billion and current lender commitments of $2.64 billion. The borrowing base is redetermined semi-annually based on certain factors including our reserves, natural gas, NGLs, and oil commodity prices, and the value of our hedge portfolio. The next redetermination of the borrowing base is scheduled to occur in April 2021. For a discussion of the risks of a decrease in the borrowing base under the Credit Facility, see "Item 1A. Risk Factors—The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility."

Our commodity hedge position provides us with additional liquidity because it provides us with the relative certainty of receiving a significant portion of our future expected revenues from operations despite potential declines in the price of natural gas. Our ability to make significant additional acquisitions for cash would require us to utilize borrowings on the Credit Facility or obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. The Credit Facility is funded by a syndicate of 25 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.

2020 Capital Spending and 2021 Capital Budget

For the year ended December 31, 2020, our total consolidated capital expenditures were approximately $785 million, including drilling and completion expenditures of $735 million, leasehold additions of $48 million, and other capital expenditures of $2 million. Our net capital budget for 2021 is $635 million. Our budget includes $590 million for drilling and completions and $45 million for leasehold expenditures. We do not budget for acquisitions. During 2021, we plan to operate an average of three drilling rigs and two completion crews and we plan to complete 65 to 70 horizontal wells in the Appalachian Basin in 2021. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

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

Based on strip prices as of December 31, 2020, we believe that net cash provided from operating activities, available borrowings under the Credit Facility and capital market transactions will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "—Debt Agreements and Contractual Obligations."

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2018, 2019 and 2020:

	Year Ended December 31,		
(in thousands)	2018	2019	2020
Net cash provided by operating activities	$ 2,081,987	1,103,458	735,640
Net cash used in investing activities	(2,350,724)	(1,041,490)	(530,061)
Net cash provided by (used in) financing activities	240,296	557,564	(205,579)
Effect of deconsolidation of Antero Midstream Partners LP	—	(619,532)	—
Net increase (decrease) in cash and cash equivalents	$ (28,441)	—	—

Our consolidated cash flow statements for the years ended December 31, 2018 and 2019 include the cash flows related to Antero Midstream Partners for periods prior to March 13, 2019. Effective March 13, 2019, the Company's cash flows include only the operating, investing and financing activities related to Antero and therefore, the cash flows for the years ended December 31, 2018 and 2019 may not be representative of our expected future cash flows. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for more information.

Year Ended December 31, 2019 Compared to Year Ended December 31, 2020

Operating Activities. Net cash provided by operating activities was $1.1 billion and $736 million for the years ended December 31, 2019 and 2020, respectively. Cash flow from operations decreased primarily due to decreases in commodity prices both before and after the effects of settled commodity derivatives and increases in gathering, compression, processing, and transportation costs.

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. For example, the impact of the COVID-19 outbreak has reduced global demand for natural gas, NGLs, and oil. 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. Cash flows used in investing activities decreased from $1.0 billion for the year ended December 31, 2019 to $530 million for the year ended December 31, 2020, primarily due to a decrease in capital expenditures of $548 million during the year ended December 31, 2020 as compared to the same period in 2019, $297 million in proceeds received in connection with the Transactions in the year ended December 31, 2019, $100 million in proceeds received in connection with the sale of shares of Antero Midstream Corporation common stock in the year ended December 31, 2019, $125 million in settlement of the water earnout impacting the year ended December 31, 2020 and $216 million in proceeds received from the VPP in the year ended December 31, 2020. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for further discussion on the Transactions.

In addition, the year ended December 31, 2019 included Antero Midstream Partners' investments in joint ventures of $25 million and capital expenditures for water handling and treatment systems and gas gathering and compression systems of $73 million. Due to the deconsolidation of Antero Midstream Partners on March 12, 2019, cash flows used in investing activities for the year ended December 31, 2020 do not include costs attributable to Antero Midstream Partner's investing activity. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements. Excluding Antero Midstream Partners, capital expenditures were $1.3 billion and $874 million for the years ended December 31, 2019 and 2020, respectively.

Total additions to unproved properties and drilling and completion costs decreased from $1.3 billion during the year ended December 31, 2019 to $826 million during the year ended December 31, 2020 primarily due to a decrease in drilling and completion activity, increased drilling and completion efficiencies and service cost deflation.

Financing Activities. Net cash flows provided by financing activities was $558 million for the year ended December 31, 2019, compared to net cash flows used in financing activities of $206 million for the year ended December 31, 2020. Net borrowings on our Credit Facility and Antero Midstream Partners' credit facility increased from $232 million during the year ended December 31, 2019 to $465 million during the year ended December 31, 2020. During the year ended December 31, 2020, approximately $1.2 billion was used to repurchase all of our 2021 Notes and repurchase a portion of our 2022 Notes, 2023 Notes and 2025 Notes, which were partially funded with borrowings on our Credit Facility, compared to $191 million used to repurchase senior notes in the year ended December 31, 2019. In addition, we repurchased and retired 28,193,237 shares of common stock for approximately $43 million during the year ended December 31, 2020 compared to repurchases of 13,390,617 shares of common stock for approximately $39 million during the year ended December 31, 2019.

During the year ended December 31, 2019, Antero Midstream Partners issued $650 million of senior notes prior to the Transactions and during the year ended December 31, 2020, we issued $288 million principal amount of 2026 Convertible Notes. Additionally, we also received $351 million for the sale of a noncontrolling interest in Martica during the year ended December 31, 2020. See Note 4—Transactions and Note 8—Long-Term Debt for more information on these transactions, respectively.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2019

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, 2019 for a discussion of the cash flows for the year ended December 31, 2018 compared to the year ended December 31, 2019.

Debt Agreements and Contractual Obligations

Debt Agreements

Senior Secured Revolving Credit Facility

The Credit Facility is with a consortium of bank lenders. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our assets and are subject to regular semi-annual redeterminations. As of December 31, 2020, the borrowing base was $2.85 billion and lender commitments were $2.64 billion. The next redetermination of the borrowing base is scheduled to occur by the end of April 2021. The Credit Facility is scheduled to mature on October 26, 2022.

As of December 31, 2020, we had $1.0 billion of borrowings with a weighted average interest rate of 3.26% and $730 million of letters of credit outstanding under the Credit Facility. As of December 31, 2019, we had $552 million of borrowings, with a weighted average interest rate of 3.28%, and $623 million of letters of credit outstanding under the Credit Facility. The Credit Facility provides for borrowing under either an Adjusted LIBO Rate or an Alternate Base Rate (each as defined in the Credit Facility).

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

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

However, many of these covenants will terminate during any Investment Grade Period (as defined in the Credit Facility).

We were in compliance with the applicable covenants and ratios as of December 31, 2019 and 2020. The actual borrowing capacity available to us may be limited by the financial ratio covenants. As of December 31, 2020, our current ratio was 2.25 to 1.0 (based on the $2.85 billion borrowing base under the Credit Facility) and our interest coverage ratio was 7.30 to 1.0.

Senior Unsecured Notes

The following table summarizes certain material terms of our senior unsecured notes and convertible notes outstanding as of December 31, 2020:

	2022 Notes	2023 Notes	2025 Notes	2026 Convertible Notes
Outstanding principal (in thousands)	$ 660,516	$ 574,182	$ 590,000	$ 287,500
Interest rate	5.125 %	5.625 %	5.00 %	4.25 %
Maturity date	December 1, 2022	June 1, 2023	March 1, 2025	September 1, 2026
Interest payment dates	June 1, Dec. 1	June 1, Dec. 1	Mar. 1, Sept. 1	Mar. 1, Sept. 1
Make-whole redemption date (1)	June 1, 2020	June 1, 2021	March 1, 2023	N/A (2)

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

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

On January 4, 2021 and January 26, 2021, we issued the 2026 Notes and 2029 Notes, respectively, at par. We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under the Credit Facility and redeem previously issued senior notes. The following table summarizes certain material terms of the 2026 Notes and 2029 Notes:

	2026 Notes	2029 Notes
Outstanding principal (in thousands)	$ 500,000	$ 700,000
Interest rate	8.375 %	7.625 %
Maturity date	July 15, 2026	February 1, 2029
Interest payment dates	Jan. 15, July 15	Feb. 1, Aug. 1
Make-whole redemption date (1)	January 15, 2026	February 1, 2027

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

Please refer to Note 8—Long Term Debt to the consolidated financial statements for more information on our senior notes.

We may, from time to time, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in 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. During the year ended December 31, 2020, we repurchased $1.4 billion principal amount of debt at a 13% weighted average discount, including all of our 2021 Notes and a portion of our 2022 Notes, 2023 Notes and 2025 Notes.

The senior notes indentures each contain restrictive covenants and restrict our ability to incur additional debt unless a pro forma minimum interest coverage ratio requirement of 2.25:1 is maintained. We were in compliance with such covenants as of December 31, 2019 and 2020.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2020 is provided in the table below. Future capital contributions to unconsolidated affiliates are excluded from the table as neither the amounts nor the timing of the obligations can be determined in advance.

	Year Ended December 31,						
(in millions)	**2021**	**2022**	**2023**	**2024**	**2025**	**Thereafter**	**Total**
Recorded contractual obligations:							
Credit Facility [1]	$ —	1,017	—	—	—	—	1,017
Antero senior notes—principal [2]	—	661	574	—	590	287	2,112
Antero senior notes—interest [2]	108	108	58	42	27	12	355
Operating leases [3]	265	268	301	335	307	1,139	2,615
Finance leases [3]	1	—	—	—	—	—	1
Imputed interest for leases [3]	346	312	274	232	187	420	1,771
Asset retirement obligations [4]	—	—	—	—	—	54	54
Unrecorded contractual obligations:							
Firm transportation [5]	1,080	1,037	1,065	1,025	985	6,948	12,140
Processing, gathering, and compression services [6]	55	52	59	59	48	114	387
Land payment obligations [7]	3	—	—	—	—	—	3
Total	$ 1,858	3,455	2,331	1,693	2,144	8,974	20,455

(1) Includes outstanding principal amounts as of December 31, 2020. This table does not include future commitment fees, interest expense, or other fees on the Credit Facility because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged. The Credit Facility is scheduled to mature on October 26, 2022.

(2) Our senior notes include the 2022 Notes, 2023 Notes, 2025 Notes and 2026 Convertible Notes but does not include the 2026 Notes (aggregate principal amount of $500 million) or the 2029 Notes (aggregate principal amount of $700 million). After December 31, 2020, we redeemed all of our 2022 Notes and equitized a portion of our 2026 Convertible Notes. See Note 8—Long-Term Debt to the consolidated financial statements for more information on these transactions.

(3) Includes contracts for services provided by drilling rigs and completion fleets, processing, gathering and compression services agreements and office and equipment leases accounted for as leases. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests. See Note 13—Leases to the consolidated financial statements for more information on our operating and finance leases.

(4) Represents the present value of our estimated asset retirement obligations. Neither the ultimate settlement amounts nor the timing of our asset retirement. obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

(5) Includes firm transportation agreements with various pipelines in order to facilitate the delivery of our production to market. These contracts commit us 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 reflect our minimum daily volumes at the reservation fee rates. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests and net of any fees for excess firm transportation marketed to third parties. None of these agreements were determined to be leases.

(6) Contractual commitments for processing, gathering, and compression services agreements represent minimum commitments under long-term agreements not accounted for as leases. The obligations determined to be leases are included within finance and operating leases in the table above.

(7) Includes contractual commitments for land acquisition agreements. The values in the table represent the minimum payments due under these arrangements. None of these agreements were determined to be leases.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that 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 carrying values of assets and liabilities 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. Our more significant accounting policies and estimates include the successful efforts method of accounting for our production activities, estimates of natural gas, NGLs, and oil reserve quantities and standardized measure of future cash flows, and impairment of proved properties. We provide an expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of our consolidated financial statements. See Note 2—Summary of Significant Accounting Policies to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method

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 charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when we determine 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 makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. We have not incurred any such charges in the years ended December 31, 2018, 2019 and 2020. The sale of a partial interest in a proved property is accounted for as a cost recovery, 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 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. 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 recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of oil and gas properties related to unproved properties for leases that have expired, or are expected to expire, was $549 million, $393 million, and $224 million for the years ended December 31, 2018, 2019 and 2020, respectively.

The successful efforts method of accounting can have a significant impact on our operational results when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activities. The initial exploratory wells may be unsuccessful and would be expensed if reserves are not found in economic quantities. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. Additionally, the application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Natural Gas, NGLs, and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

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. Current accounting guidance allows only proved natural gas, NGLs, and oil reserves to be included in our financial statement disclosures. 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 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 field. 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. Any significant revisions could affect the future amortization rates of capitalized 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. Under GAAP for successful efforts accounting, if the carrying amount exceeds the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties.

We did not record any impairments for proved properties during the years ended December 31, 2018 and 2020. During the year ended December 31, 2019 the Utica Shale carrying value exceeded the estimated fair value of the Utica Shale assets based on sales of other properties. As a result, we recorded an impairment of $881 million related to proved oil and gas properties in the Utica Shale during the year ended December 31, 2019.

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. We estimate that if strip prices were to decline by approximately 2.5% from future pricing levels as of December 31, 2020, estimated future net revenues for our Utica properties would approximate the carrying amount of the properties and further evaluation of the fair value of those properties would be required in order to determine if an impairment charge would be necessary under GAAP. For our Marcellus properties, strip pricing would have to decline by more than approximately 10% from year-end 2020 levels before further evaluation of those properties would be required in order to determine if an impairment charge would be necessary under GAAP. We are unable, however, to predict commodity prices with any greater precision than the futures market.

Fair Value Measurement

The FASB ASC Topic 820, *Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and sets forth disclosure requirements 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., the initial recognition of asset retirement obligations and impairments of long-lived assets). The fair value is the price that we estimate 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. Our 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, that are observable for the asset or liability, either directly or indirectly.

We account for our investment in Antero Midstream under the equity method of accounting. We evaluate our equity method investment for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the fair value of the investment to the carrying value of the investment to determine whether potential impairment has occurred. If the fair value is less than the carrying value and management considers the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the financial statements as an impairment loss. See Note 10—Equity-Based Compensation and Retention Awards to the consolidated financial statements for further discussion on our equity method investments.

As of December 31, 2019 and March 31, 2020, we determined that events and circumstances indicated that the carrying value had experienced an other-than-temporary decline and we recorded impairment expense of $468 million and $611 million, respectively. The fair value of the equity method investment in Antero Midstream was based on the quoted market common stock price of Antero Midstream as of December 31, 2019 (Level 1).

Income Taxes

We are subject to state and federal income taxes, but are currently not in a cash tax paying position with respect to federal income taxes. The difference between our financial statement income tax expense and our federal income tax liability is primarily due to the differences in the tax and financial statement treatment of oil and gas properties and derivative instruments. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income, primarily from derivative instruments, oil and gas properties and net operating loss ("NOL") carryforwards. As of December 31, 2020, we have U.S. federal and state NOLs expiring at various dates from 2032 to 2040 while others have no expiration date, which resulted in the recognition of significant deferred tax assets. We record deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets. We record a deferred income tax benefit to the extent our deferred tax assets exceed our deferred tax liabilities.

We record a valuation allowance when we believe all or a portion of our deferred tax assets will not be realized. In assessing the realizability of our deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred tax assets is dependent upon our ability to generate future taxable income during the periods in which our deferred tax assets are deductible. Management considers the scheduled reversal of deferred 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 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, 2020, we have recognized a valuation allowance of $46 million for NOLs we do not expect to realize that are primarily attributable to states in which we no longer operate.

The calculation of deferred tax assets and liabilities involves uncertainties in the application of complex tax laws and regulations. We recognize in our financial statements those tax positions which we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities.

New Accounting Pronouncements

On August 5, 2020, the FASB issued Accounting Standards Update No. 2020-06, *Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*, which eliminates the cash conversion model in ASC 470-20, *Debt with Conversion and Other Options*, that require separate accounting for conversion features, and instead, allows the debt instrument and conversion features to be accounted for as a single debt instrument. The new standard becomes effective on January 1, 2022, and early adoption is permitted. We are evaluating our plans for adoption, including the adoption date and transition method.

Upon adoption of this new standard, we expect to reclassify $85 million, net of deferred income taxes and equity issuance costs, to long-term debt and deferred income tax liability, as applicable, from stockholders' equity as of December 31, 2020, which amount is subject to adjustment for any conversions until adoption of this new standard. Additionally, annual interest expense for the 2026 Convertible Notes will be based on an effective interest rate of 4.8% as compared to 15.1% for the year ended December 31, 2020. We do not believe that adoption of the standard will impact our operational strategies or development prospects.

Off-Balance Sheet Arrangements

As of December 31, 2020, we did not have any off-balance sheet arrangements other than contractual commitments for firm transportation, gas processing and fractionation, gathering, and compression services and land payment obligations. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for our commitments under these agreements.

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 product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flows caused by changes in commodity prices, we enter into financial derivative instruments for a portion of our natural gas, NGLs, and oil production when management believes that favorable future prices can be secured.

Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas, NGLs, and oil price fluctuations. 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, or basis differential swaps. These contracts are financial instruments, and do not require or allow for physical delivery of the hedged commodity. As of December 31, 2020, our commodity derivatives included fixed price swaps and basis differential swaps at index-based pricing.

As of December 31, 2020, we had in place natural gas swaps covering portions of our projected production through 2024. Our commodity hedge position as of December 31, 2020 is summarized in Note 12—Derivative Instruments to our consolidated financial statements. Under the Credit Facility, we are permitted to hedge up to 75% of our projected production for the next 60 months. We may enter into hedge contracts with a term greater than 60 months, and for no longer than 72 months, for up to 65% of our estimated production. Based on our production and our fixed price swap contracts that settled during the year ended December 31, 2020, our revenues would have decreased by approximately $48 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, 2020.

All derivative instruments, other than those that meet the normal purchase and normal sale scope exception, 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. We present total gains or losses on commodity derivatives (for both settled derivatives and derivative positions which remain open) within operating revenues as "Commodity derivative fair value gains (losses)."

Mark-to-market adjustments of derivative instruments cause earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled or monetized prior to settlement. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are only impacted when the associated derivative contracts are settled or monetized by making or receiving payments to or from the counterparty. As of December 31, 2020, the estimated fair value of our commodity derivative instruments was a net asset of $22 million, comprised of current and noncurrent assets and liabilities. As of December 31, 2019, the estimated fair value of our commodity derivative instruments was a net asset of $746 million, comprised of current and noncurrent assets and current liabilities.

By removing price volatility from a portion of our expected production through December 2023, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from the following: commodity derivative contracts ($22 million as of December 31, 2020) and the sale of our natural gas, NGLs, and oil production ($380 million as of December 31, 2020) which we market to energy companies, end users, and refineries.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of a counterparty to perform under the terms of a derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions that management deems to be competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have commodity hedges in place with 17 different counterparties, 13 of which are lenders under the Credit Facility. The fair value of our commodity net derivative contracts of approximately $22 million as of December 31, 2020 included the following net derivative assets by bank counterparty: Morgan Stanley - $35 million; Canadian Imperial Bank of Commerce - $25 million; Scotiabank - $14 million; Natixis - $5 million; DNB Capital - $2 million; and Truist $1 million. 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, 2020 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by the Credit Facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2020, we did not have any past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to the concentration of our receivables from several significant customers for sales of natural gas, NGLs, and oil. We generally do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us, or their insolvency or liquidation, may adversely affect our financial results.

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 annual interest rate incurred on the Credit Facility during the year ended December 31, 2020 was approximately 3.24%. We estimate that a 1.0% increase in the applicable average interest rates for the year ended December 31, 2020 would have resulted in an estimated $8.7 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, 2020 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, 2020 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, 2020.

The effectiveness of our internal control over financial reporting as of December 31, 2020 has been audited by KPMG LLP, an independent registered public accounting firm which also audited our consolidated financial statements as of and for the year ended December 31, 2020, as stated in their report which appears beginning on page F-2 in this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

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 2021 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 2021 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 2021 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 2021 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 2021 Annual Meeting of Stockholders.

PART IV

ITEM 15. EXHIBIT AND FINANCIAL STATEMENT SCHEDULES

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

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

(a)(3) Exhibits.

Exhibit Number	Description of Exhibit
2.1	Simplification Agreement, dated as of October 9, 2018, by and among AMGP GP LLC, Antero Midstream GP LP, Antero IDR Holdings LLC, Arkrose Midstream Preferred Co LLC, Arkrose Midstream NewCo Inc., Arkrose Midstream Merger Sub LLC, Antero Midstream Partners GP LLC and Antero Midstream Partners LP (incorporated by reference to Exhibit 2.1 to Antero Midstream GP LP's Current Report on Form 8-K (Commission File No. 001-38075) filed on October 10, 2018).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).

Exhibit Number	Description of Exhibit
3.2	Amended and Restated Bylaws of Antero Resources Corporation (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.1	Indenture related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, 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 May 8, 2014).
4.2	Form of 5.125% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.3	First Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of November 24, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on November 26, 2014).
4.4	Second Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of January 21, 2015, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.6 to the Company's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on January 22, 2015).
4.5	Third Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated March 12, 2019, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.6	Fourth Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated June 3, 2020, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 29, 2020).
4.7	Indenture related to the 5.625% Senior Notes due 2023, dated as of March 17, 2015, 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 March 18, 2015).
4.8	Form of 5.625% Senior Note due 2023 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 333-164876) filed on March 18, 2015).
4.9	First Supplemental Indenture related to the 5.625% Senior Notes due 2023, dated March 12, 2019, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.10	Second Supplemental Indenture related to the 5.625% Senior Notes due 2023, dated June 3, 2020, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 29, 2020).
4.11	Indenture related to the 5.0% Senior Notes due 2025, dated as of December 21, 2016, 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 December 29, 2016).
4.12	Form of 5.0% Senior Note due 2025 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 333-164876) filed on December 29, 2016).
4.13	First Supplemental Indenture related to the 5.0% Senior Notes due 2025, dated March 12, 2019, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.14	Second Supplemental Indenture related to the 5.0% Senior Notes due 2025, dated June 3, 2020, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 29, 2020).
4.15	Indenture related to the 4.25% Convertible Senior Notes due 2026, dated as of August 21, 2020, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee

Exhibit Number	Description of Exhibit
	(incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on August 21, 2020).
4.16	Form of 4.25% Convertible Senior Note due 2026 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on August 21,2020).
4.17	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).
4.18	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).
4.19	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).
4.20	Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended (incorporated by reference to Exhibit 4.20 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 12, 2020).
4.21	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).
4.22	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).
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	Fifth Amended and Restated Credit Agreement, dated as of October 26, 2017, by and among Antero Resources Corporation, the lenders party thereto, and JPMorgan Chase Bank N.A., as Administrative Agent (incorporated by

Exhibit Number	Description of Exhibit
	reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on November 1, 2017).
10.11	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of December 21, 2018 (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 28, 2018).
10.12	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).
10.13	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of December 20, 2019, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 12, 2020).
10.14	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 29, 2020, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 29, 2020).
10.15	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated as of June 5, 2020, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, 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 July 29, 2020).
10.16	Fifth Amendment to Fifth Amended and Restated Credit Agreement, dated as of June 12, 2020, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, 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 29, 2020).
10.17†	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).
10.18†	Antero Resources Corporation Long-Term Incentive Plan, effective as of October 1, 2013 (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (Commission File No. 001-36120) filed on October 11, 2013).
10.19†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 25, 2015).
10.20†	Form of Bonus Stock Grant Notice and Bonus Stock Agreement (Form for Non-Employee Directors) under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 24, 2016).
10.21†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement (Form for Special Retention Awards) under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on February 12, 2016).
10.22†	Global Amendment to Grant Notices and Award Agreements Under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).
10.23†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 31, 2019).
10.24†	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).
10.25†	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 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 10, 2018).

Exhibit Number	Description of Exhibit
10.26†	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).
10.27†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Form for Special Retention Awards) under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 29, 2020).
10.28†	Form of Retention Award Grant Notice and Retention Award Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 29, 2020).
10.29†	Antero Resources Corporation 2020 Long-Term Incentive Plan, effective June 17, 2020 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on June 23, 2020).
10.30†	Form of Retention Award Grant Notice and Retention Award Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (Employees) (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2020).
10.31†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2020).
10.32†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the Antero Resources Corporation 2020 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2020).
21.1*	Subsidiaries of Antero Resources Corporation.
22.1*	List of Guarantor Subsidiaries.
23.1*	Consent of KPMG LLP.
23.2*	Consent of KPMG LLP.
23.3*	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).
99.1*	Report of DeGolyer and MacNaughton, dated as of January 29, 2021, for proved reserves as of December 31, 2020.
99.2	Report of DeGolyer and MacNaughton, dated as of January 21, 2020, for proved reserves as of December 31, 2019 (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, 2020).
99.3	Report of DeGolyer and MacNaughton, dated as of January 11, 2019, for proved reserves as of December 31, 2018 (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 13, 2019).
99.4*	Financial Statements of Antero Midstream Corporation
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2020, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Consolidated Statements of Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document).

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

SIGNATURES

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

ANTERO RESOURCES CORPORATION

By: /s/ GLEN C. WARREN, JR.
Glen C. Warren, Jr.
President, Chief Financial Officer and Secretary

Date: February 17, 2021

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

Signature	Title	Date
/s/ PAUL M. RADY Paul M. Rady	Chairman of the Board, Director and Chief Executive officer (principal executive officer)	February 17, 2021
/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr.	President, Director, Chief Financial Officer and Secretary (principal financial officer)	February 17, 2021
/s/ SHERI L. PEARCE Sheri L. Pearce	Vice President, Accounting and Chief Accounting Officer (principal accounting officer)	February 17, 2021
/s/ ROBERT J. CLARK Robert J. Clark	Director	February 17, 2021
/s/ BENJAMIN A. HARDESTY Benjamin A. Hardesty	Director	February 17, 2021
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 17, 2021
/s/ PAUL J. KORUS Paul J. Korus	Director	February 17, 2021
/s/ JACQUELINE C. MUTSCHLER Jacqueline C. Mutschler	Director	February 17, 2021
/s/ VICKY SUTIL Vicky Sutil	Director	February 17, 2021
/s/ THOMAS B. TYREE, JR. Thomas B. Tyree, Jr.	Director	February 17, 2021

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, 2019 and 2020, the related consolidated statements of operations and comprehensive loss, equity, and cash flows for each of the years in the three-year period ended December 31, 2020, 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, 2020, 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, 2019 and 2020, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2020, 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, 2020 based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Codification Topic 842, *Leases*.

Basis for Opinions

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

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

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

Critical Audit Matter

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

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

As discussed in Note 2 to the consolidated financial statements, the Company calculates depletion expense related to proved oil and gas properties using the units-of-production method. Under such method, capitalized costs are amortized over total estimated proved oil and gas reserves. For the year ended December 31, 2020, the Company recorded depletion expense related to proved oil and gas properties of $854 million. Estimating proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration forecasted production, operating cost assumptions and forecasted oil and gas prices inclusive of market differentials. The Company's internal reservoir engineers estimate proved oil and gas reserves, and the Company engages external reservoir engineering specialists to perform an independent evaluation of those proved oil and gas reserve estimates.

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

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

/s/ KPMG LLP

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

Denver, Colorado
February 17, 2021

ANTERO RESOURCES CORPORATION

Consolidated Balance Sheets

(In thousands, except per share amounts)

	December 31, 2019	December 31, 2020
Assets		
Current assets:		
Accounts receivable	$ 46,419	28,457
Accounts receivable, related parties	125,000	—
Accrued revenue	317,886	425,314
Derivative instruments	422,849	105,130
Other current assets	10,731	15,238
Total current assets	922,885	574,139
Property and equipment:		
Oil and gas properties, at cost (successful efforts method):		
Unproved properties	1,368,854	1,175,178
Proved properties	11,859,817	12,260,713
Gathering systems and facilities	5,802	5,802
Other property and equipment	71,895	74,361
	13,306,368	13,516,054
Less accumulated depletion, depreciation, and amortization	(3,327,629)	(3,869,116)
Property and equipment, net	9,978,739	9,646,938
Operating leases right-of-use assets	2,886,500	2,613,603
Derivative instruments	333,174	47,293
Investment in unconsolidated affiliate	1,055,177	255,082
Other assets	21,094	13,790
Total assets	$ 15,197,569	13,150,845
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 14,498	26,728
Accounts payable, related parties	97,883	69,860
Accrued liabilities	400,850	343,524
Revenue distributions payable	207,988	198,117
Derivative instruments	6,721	31,242
Short-term lease liabilities	305,320	266,024
Deferred revenue, VPP	—	45,257
Other current liabilities	6,879	2,302
Total current liabilities	1,040,139	983,054
Long-term liabilities:		
Long-term debt	3,758,868	3,001,593
Deferred income tax liability	781,987	412,252
Derivative instruments	3,519	99,172
Long-term lease liabilities	2,583,678	2,348,785
Deferred revenue, VPP	—	156,024
Other liabilities	58,635	59,694
Total liabilities	8,226,826	7,060,574
Commitments and contingencies (Notes 15 and 16)		
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; 295,941 shares and 268,672 shares issued and outstanding at December 31, 2019 and 2020, respectively	2,959	2,686
Additional paid-in capital	6,130,365	6,195,497
Accumulated earnings (deficit)	837,419	(430,478)
Total stockholders' equity	6,970,743	5,767,705
Noncontrolling interests	—	322,566
Total equity	6,970,743	6,090,271
Total liabilities and equity	$ 15,197,569	13,150,845

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Loss

(In thousands, except per share amounts)

	Year Ended December 31,		
	2018	2019	2020
Revenue and other:			
Natural gas sales	$ 2,287,939	2,247,162	1,809,952
Natural gas liquids sales	1,177,777	1,219,162	1,161,683
Oil sales	187,178	177,549	112,270
Commodity derivative fair value gains (losses)	(87,594)	463,972	79,918
Gathering, compression, water handling and treatment	21,344	4,478	—
Marketing	458,901	292,207	310,572
Marketing derivative fair value gains	94,081	—	—
Amortization of deferred revenue, VPP	—	—	14,507
Other income	—	4,160	2,797
Total revenue	4,139,626	4,408,690	3,491,699
Operating expenses:			
Lease operating	136,153	145,720	98,865
Gathering, compression, processing, and transportation	1,339,358	2,146,647	2,530,838
Production and ad valorem taxes	126,474	125,142	106,775
Marketing	686,055	549,814	469,404
Exploration	4,958	884	1,083
Impairment of oil and gas properties	549,437	1,300,444	223,770
Impairment of midstream assets	9,658	14,782	—
Depletion, depreciation, and amortization	972,465	914,867	861,870
Accretion of asset retirement obligations	2,819	3,762	3,421
General and administrative (including equity-based compensation expense of $70,414, $23,559 and $23,317 in 2018, 2019 and 2020, respectively)	240,344	178,696	134,482
Contract termination and rig stacking	—	14,026	14,290
Loss on sale of assets	—	951	348
Total operating expenses	4,067,721	5,395,735	4,445,146
Operating income (loss)	71,905	(987,045)	(953,447)
Other income (expense):			
Interest expense, net	(286,743)	(228,111)	(199,872)
Equity in earnings (loss) of unconsolidated affiliates	40,280	(143,216)	(62,660)
Gain on early extinguishment of debt	—	36,419	175,962
Gain on deconsolidation of Antero Midstream Partners LP	—	1,406,042	—
Water earnout	—	125,000	—
Loss on the sale of equity method investment shares	—	(108,745)	—
Impairment of equity method investment	—	(467,590)	(610,632)
Transaction expense	—	—	(7,244)
Total other income (expenses)	(246,463)	619,799	(704,446)
Loss before income taxes	(174,558)	(367,246)	(1,657,893)
Provision for income tax benefit	128,857	74,110	397,482
Net loss and comprehensive loss including noncontrolling interests	(45,701)	(293,136)	(1,260,411)
Less: net income and comprehensive income attributable to noncontrolling interests	351,816	46,993	7,486
Net loss and comprehensive loss attributable to Antero Resources Corporation	$ (397,517)	(340,129)	(1,267,897)
Loss per share—basic	$ (1.26)	(1.11)	(4.65)
Loss per share—diluted	$ (1.26)	(1.11)	(4.65)
Weighted average number of shares outstanding:			
Basic	316,036	306,400	272,433
Diluted	316,036	306,400	272,433

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Equity

(In thousands)

	Common Stock		Additional paid-in capital	Accumulated earnings (deficit)	Noncontrolling interests	Total equity
	Shares	Amount				
Balances, December 31, 2017	316,379	$ 3,164	6,570,952	1,575,065	726,955	8,876,136
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,360	13	(11,504)	—	—	(11,491)
Issuance of common units by Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(16,536)	—	11,007	(5,529)
Effects of changes in ownership interests in consolidated subsidiaries	—	—	8,637	—	(8,637)	—
Distributions to noncontrolling interests	—	—	—	—	(267,271)	(267,271)
Repurchases and retirements of common stock	(9,145)	(91)	(128,993)	—	—	(129,084)
Equity-based compensation	—	—	62,618	—	7,796	70,414
Other	—	—	—	—	3	3
Net income (loss) and comprehensive income (loss)	—	—	—	(397,517)	351,816	(45,701)
Balances, December 31, 2018	308,594	3,086	6,485,174	1,177,548	821,669	8,487,477
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	738	7	(2,371)	—	—	(2,364)
Issuance of common units by Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—		(85)	—	56	(29)
Effect of deconsolidation of Antero Midstream Partners LP	—	—	(336,172)	—	(784,744)	(1,120,916)
Distributions to noncontrolling interest	—	—	—	—	(85,076)	(85,076)
Repurchases and retirements of common stock	(13,391)	(134)	(38,638)	—	—	(38,772)
Equity-based compensation	—	—	22,457	—	1,102	23,559
Net income (loss) and comprehensive income (loss)	—	—	—	(340,129)	46,993	(293,136)
Balances, December 31, 2019	295,941	2,959	6,130,365	837,419	—	6,970,743
Issuance of common units in Martica Holdings, LLC	—	—	—	—	351,000	351,000
Equity component of 2026 Convertible Notes, net	—	—	85,407	—	—	85,407
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	924	9	(431)	—	—	(422)
Distributions to noncontrolling interest	—	—	—	—	(35,920)	(35,920)
Repurchases and retirements of common stock	(28,193)	(282)	(43,161)	—	—	(43,443)
Equity-based compensation	—	—	23,317	—	—	23,317
Net income (loss) and comprehensive income (loss)	—	—	—	(1,267,897)	7,486	(1,260,411)
Balances, December 31, 2020	268,672	$ 2,686	6,195,497	(430,478)	322,566	6,090,271

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Cash Flows

(In thousands)

	Year Ended December 31, 2018	2019	2020
Cash flows provided by (used in) operating activities:			
Net loss including noncontrolling interests	$ (45,701)	(293,136)	(1,260,411)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion	975,284	918,629	865,291
Impairments	559,095	1,782,816	834,402
Commodity derivative fair value losses (gains)	87,594	(463,972)	(79,918)
Gains on settled commodity derivatives	243,112	325,090	794,684
Premium paid on derivative contract	(13,318)	—	—
Proceeds from derivative monetizations	370,365	—	9,007
Gains on settled marketing derivatives	72,687	—	—
Marketing derivative fair value gains	(94,081)	—	—
Loss on sale of assets	—	951	348
Equity-based compensation expense	70,414	23,559	23,317
Deferred income tax benefit	(128,857)	(79,158)	(397,482)
Gain on early extinguishment of debt	—	(36,419)	(175,962)
Loss on the sale of equity method investment shares	—	108,745	—
Equity in (earnings) loss of unconsolidated affiliates	(40,280)	143,216	62,660
Water earnout	—	(125,000)	—
Gain on deconsolidation of Antero Midstream Partners LP	—	(1,406,042)	—
Distributions/dividends of earnings from unconsolidated affiliates	46,415	157,956	171,022
Amortization of deferred revenue	—	—	(14,507)
Amortization of debt issuance costs, debt discount, debt premium and other	4,681	10,681	12,236
Changes in current assets and liabilities:			
Accounts receivable	(15,156)	31,631	(9,492)
Accrued revenue	(174,706)	156,941	(107,428)
Other current assets	(5,817)	(1,025)	(5,507)
Accounts payable including related parties	9,307	(27,996)	(19,282)
Accrued liabilities	63,562	(25,762)	37,954
Revenue distributions payable	101,210	(102,839)	(5,203)
Other current liabilities	(3,823)	4,592	(89)
Net cash provided by operating activities	2,081,987	1,103,458	735,640
Cash flows provided by (used in) investing activities:			
Additions to unproved properties	(172,387)	(88,682)	(45,129)
Drilling and completion costs	(1,488,573)	(1,254,118)	(826,265)
Additions to water handling and treatment systems	(97,699)	(24,416)	—
Additions to gathering systems and facilities	(444,413)	(48,239)	—
Additions to other property and equipment	(7,514)	(6,700)	(2,963)
Settlement of water earnout	—	—	125,000
Investments in unconsolidated affiliates	(136,475)	(25,020)	—
Proceeds from sale of common stock of Antero Midstream Corporation	—	100,000	—
Proceeds from the Antero Midstream Partners LP Transactions	—	296,611	—
Proceeds from asset sales	—	1,983	701
Proceeds from VPP sale, net	—	—	215,789
Change in other assets	(3,663)	7,091	2,806
Net cash used in investing activities	(2,350,724)	(1,041,490)	(530,061)
Cash flows provided by (used in) financing activities:			
Repurchases of common stock	(129,084)	(38,772)	(43,443)
Issuance of senior notes by Antero Midstream Partners LP	—	650,000	—
Issuance of convertible notes	—	—	287,500
Repayment of senior notes	—	(191,092)	(1,219,019)
Borrowings (repayments) on bank credit facilities, net	660,379	232,000	465,000
Payment of debt issuance costs	(2,169)	(4,547)	(8,984)
Sale of noncontrolling interest	—	—	351,000
Distributions to noncontrolling interests in Antero Midstream Partners LP	(267,271)	(85,076)	—
Distributions to noncontrolling interests in Martica Holdings LLC	—	—	(35,920)
Employee tax withholding for settlement of equity compensation awards	(17,020)	(2,389)	(422)
Other	(4,539)	(2,560)	(1,291)
Net cash provided by (used in) financing activities	240,296	557,564	(205,579)
Effect of deconsolidation of Antero Midstream Partners LP	—	(619,532)	—
Net decrease in cash and cash equivalents	(28,441)	—	—
Cash and cash equivalents, beginning of period	28,441	—	—
Cash and cash equivalents, end of period	$ —	—	—

(Continued)

ANTERO RESOURCES CORPORATION

Consolidated Statements of Cash Flows

(In thousands)

	Year Ended December 31,		
	2018	**2019**	**2020**
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 275,769	224,331	192,302
Decrease in accounts payable and accrued liabilities for additions to property and equipment	$ (47,717)	(15,897)	(94,619)

See accompanying notes to consolidated financial statements.

(1) Organization

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 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 are 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 accounting principles generally accepted in the United States ("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, 2019 and 2020, and the results of its operations and its cash flows for the years ended December 31, 2018, 2019 and 2020. 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, any entities in which the Company owns a controlling interest, and variable interest entities ("VIEs") for which the Company is the primary beneficiary.

Through March 12, 2019, Antero Midstream Partners LP ("Antero Midstream Partners"), a publicly traded limited partnership, was included in the consolidated financial statements of Antero. Prior to the Closing (defined in Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements), the Company's ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and Antero Resources consolidated Antero Midstream Partners' financial position and results of operations into its consolidated financial statements. The Transactions (defined in Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements) resulted in the exchange of the limited partner interest Antero Resources owned in Antero Midstream Partners for common stock of Antero Midstream Corporation representing an approximate 31% interest as of March 13, 2019. As a result, Antero Resources' controlling interest in Antero Midstream Partners was converted to an interest in Antero Midstream Corporation that provides significant influence, but not control, over Antero Midstream Corporation. Thus, effective March 13, 2019, Antero no longer consolidates Antero Midstream Partners in its consolidated financial statements and accounts for its interest in Antero Midstream Corporation using the equity method of accounting. As of December 31, 2019 and 2020, the Company had a 28.7% and 29.2% interest, respectively, in Antero Midstream Corporation. See Note 6—Equity Method Investments and Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for further discussion on equity method investments and the Transactions, respectively.

For the year ended December 31, 2020, the Company determined that Martica Holdings LLC ("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 4—Transactions); and

- Antero provides accounting, administrative and other services to Martica under a Management Services Agreement.

All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements. The noncontrolling interest in the Company's consolidated financial statements for the years ended December 31, 2018 and 2019 represents the interests in Antero Midstream Partners that were owned by the public prior to the Transactions, and the incentive distribution rights in Antero Midstream Partners. The noncontrolling interest in the Company's consolidated financial statements for the year ended December 31, 2020 represents the interest in Martica owned by third parties. See Note 4—Transactions to the consolidated financial statements for more information on the sale of this noncontrolling interest. Martica is a discrete entity and the assets and credits of Martica are not available to satisfy the debts and obligations of the Company or its other subsidiaries.

Investments in entities for which the Company exercises significant influence, but not control, are accounted for under the equity method. The Company's judgment regarding the level of influence over its equity method investments includes considering key factors such as Antero's ownership interest, representation on the board of directors, and participation in the policy-making decisions of equity method investees. Such investments are included in Investment in unconsolidated affiliate on the Company's consolidated balance sheets. Income (loss) from investees that are accounted for under the equity method is included in Equity in earnings (loss) of unconsolidated affiliates on the Company's consolidated statements of operations and cash flows. When Antero records its proportionate share of net income or net loss, it is recorded in equity in earnings (loss) of unconsolidated affiliates in the statements of operations and the carrying value of that investment on the Company's balance sheet. When a distribution is received, it is recorded as a reduction to the carrying value of that investment on the Company's balance sheet. The Company's equity in earnings of unconsolidated affiliates is adjusted for intercompany transactions and the basis differences recognized due to the difference between the cost of the equity method investment in Antero Midstream Corporation and the amount of underlying equity in the net assets of Antero Midstream Partners as of the date of deconsolidation.

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

(c) Use of Estimates

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

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

(d) Risks and Uncertainties

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

(e) Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short term nature of these instruments. From time to time, the Company may be in the position of a "book overdraft" in which outstanding checks exceed cash and cash equivalents. The Company classifies book overdrafts in accounts payable and revenue distributions payable within its consolidated balance sheets, and classifies the change in accounts payable associated with book overdrafts as an operating activity within its consolidated statements of cash flows. As of December 31, 2020, the book overdraft included within accounts payable and revenue distributions payable were $11 million and $15 million, respectively. As of December 31, 2019, the book overdraft included within accounts payable and revenue distributions payable were $7 million and $18 million, respectively.

(f) Oil and Gas Properties

The Company accounts for its natural gas, NGLs, and oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense 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 makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. During the year ended December 31, 2019, the Company recorded an impairment expense of $26 million for design and initial costs related to pads that are no longer planned to be placed into service. The Company incurred no such expenses during the years ended December 31, 2018 and 2020. The sale of a partial interest in a proved property is accounted for as a cost recovery, 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 recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties was $549 million, $393 million, and $224 million for the years ended December 31, 2018, 2019 and 2020, 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 carrying amount of the Company's proved properties in the Utica Shale exceeded the estimated undiscounted future cash flows based on future commodity prices as of September 30, 2019. The Company estimated the fair value of the Utica Shale assets based on sales of other properties, estimates of proved reserves, estimated future commodity prices and future production estimates. As a result, the Company recorded an impairment expense of $881 million related to proved properties in the Utica Shale during the third quarter of 2019. The Company did not incur any impairment expenses related to proved properties in the Utica Shale for the years ended December 31, 2018 and 2020. The Company did not record any impairment expenses associated with its proved properties in the Marcellus Shale during the years ended December 31, 2018, 2019 and 2020.

As of December 31, 2020, 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 $832 million, $884 million, and $854 million for the years ended December 31, 2018, 2019 and 2020, respectively.

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

The Company evaluates its long-lived assets other than oil and gas properties for impairment when events or changes in circumstances indicate that the related carrying values of the assets may not be recoverable. Generally, the basis for making such assessments is undiscounted future cash flow projections for the assets being assessed. If the carrying values of the assets are deemed not recoverable, the carrying values are reduced to the estimated fair values, which are based on discounted future cash flows using assumptions as to revenues, costs, and discount rates typical of third party market participants, which is a Level 3 fair value measurement.

Impairment of long-lived assets other than oil and gas properties were $10 million and $15 million for the years ended December 31, 2018 and 2019, respectively, and were associated with midstream assets. There were no such impairments for the year ended December 31, 2020.

(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 $9 million, $8 million, and $8 million for the years ended December 31, 2018, 2019 and 2020, respectively. A gain or loss is recognized upon the sale or disposal of other property and equipment.

(i) Debt Issuance Costs

Debt issuance costs represent loan origination fees and other initial borrowing costs. Such costs are capitalized and included in Other assets on the consolidated balance sheets if related to the Company's revolving 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 (as defined below in Note 8—Long-Term Debt). 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, 2020, the Company had $3 million of unamortized debt issuance costs included in other long-term assets, and $16 million of unamortized debt issuance costs included as a reduction to long-term debt. As of December 31, 2019, the Company had $7 million of unamortized debt issuance costs included in other long term assets and $19 million of unamortized debt issuance costs included as a reduction to long-term debt. The amounts amortized and the write-off of previously deferred debt issuance costs were $13 million, $11 million, and $8 million for the years ended December 31, 2018, 2019 and 2020, respectively.

(j) Derivative Financial Instruments

In order to manage its exposure to natural gas, NGLs, and oil price volatility, the Company enters into derivative transactions from time to time, which may include commodity swap agreements, basis swap agreements, collar agreements 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. 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. 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, 2019 and 2020, 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 Corporation 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.

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.

(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.

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.

(o) Deferred Revenue

Under the terms of the VPP (as defined below in Note 4—Transactions), 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 Accounting Standard Codifications ("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. See Note 4—Transactions to the consolidated financial statements for further discussion of the VPP.

(p) Gathering, Compression, Water Handling and Treatment Revenue

Substantially all revenues from the gathering, compression, water handling and treatment operations were derived from transactions for services Antero Midstream Partners provided to the Company's exploration and production operations through March 12, 2019 and were eliminated in consolidation. Effective March 13, 2019, Antero Midstream Partners is no longer consolidated in Antero's results. See Note 3—Deconsolidation of Antero Midstream Partners LP and Note 18—Segment Information to the consolidated financial statements for further discussion on the Transactions and the Company's reportable segments, respectively. The portion of such fees shown in the Company's consolidated financial statements prior to March 13, 2019 represent amounts charged to interest owners in Antero-operated wells, as well as fees charged to other third parties for water handling and treatment services provided by Antero Midstream Partners or usage of Antero Midstream Partners' gathering and compression systems. For gathering and compression revenue, Antero Midstream Partners satisfied its performance obligations and recognized revenue when low pressure volumes were delivered to a compressor station, high pressure volumes were delivered to a processing plant or transmission pipeline, and compression volumes were delivered to a high pressure line. Revenue was recognized based on the per Mcf gathering or compression fee charged by Antero Midstream Partners in accordance with the gathering and compression agreement. For water handling and treatment revenue, Antero Midstream Partners satisfied its performance obligations and recognized revenue when the fresh water volumes were delivered to the hydration unit of a specified well pad and the wastewater volumes were delivered to its wastewater treatment facility. For services contracted through third-party providers, Antero Midstream Partners' performance obligation was satisfied when the services performed by the third-party providers were completed. Revenue was recognized based on the per barrel fresh water delivery or wastewater treatment fee charged by Antero Midstream Partners in accordance with the water services agreement.

(q) Concentrations of Credit Risk

The Company's revenues are derived principally from uncollateralized sales to purchasers in the oil and gas industry or the utilities industry. The concentration of credit risk in two related industries affects the Company's overall exposure to credit risk because purchasers may be similarly affected by changes in economic and other conditions. The Company has not experienced significant credit losses on its receivables.

The Company's sales to major customers (purchases in excess of 10% of total sales) for the years ended December 31, 2018, 2019 and 2020 are as follows:

Year Ended December 31, 2018	
Mercuria Energy America, Inc.	14 %
Tenaska Marketing Ventures	13 %
Year Ended December 31, 2019	
Sabine Pass Liquefaction LLC	16 %
WGL Midstream	15 %
Year Ended December 31, 2020	
Sabine Pass Liquefaction LLC	11 %
WGL Midstream	11 %

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 17 different counterparties. The fair value of the Company's commodity net derivative contracts is approximately $22 million as of December 31, 2020 and primarily included the following net derivative assets by bank counterparty: Morgan Stanley - $35 million; Canadian Imperial Bank of Commerce - $25 million; Scotiabank - $14 million; Natixis - $5 million; DNB Capital - $2 million; and Truist $1 million. 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, 2020 for each of the European and American banks. The Company believes that all of these institutions currently are acceptable credit risks.

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

(r) Income Taxes

The Company recognizes deferred tax assets and liabilities for temporary differences resulting from net operating loss ("NOL") carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in tax laws or tax rates is recognized in income during the period such changes are enacted. Deferred 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 tax assets will not be realized.

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

(s) Fair Value Measurements

The Financial Accounting Standards Board ("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 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.

(t) Industry Segments and Geographic Information

Management has evaluated how the Company is organized and managed and has identified the following segments: (1) the exploration, development, and production of natural gas, NGLs, and oil; (2) marketing and utilization of excess firm transportation capacity and (3) midstream services through the Company's equity method investment in Antero Midstream Corporation. Through March 12, 2019, the results of Antero Midstream Partners were included in the consolidated financial statements of Antero. Effective March 13, 2019, Antero no longer consolidated the results of Antero Midstream Partners in Antero's results; however, the Company's segment disclosures include the Company's equity method investment in Antero Midstream Corporation due to its significance to the Company's operations. See Note 3—Deconsolidation of Antero Midstream Partners LP and Note 18—Segment Information to the consolidated financial statements for further discussion on the Transactions and the Company's reportable segments, respectively.

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.

(u) Earnings (Loss) Per Common Share

Earnings (loss) per common share—basic for each period is computed by dividing net income (loss) attributable to Antero by the basic weighted average number of shares outstanding during the period. Earnings (loss) per common share—diluted for each period is computed after giving consideration to the potential dilution from (i) outstanding equity awards, calculated using the treasury stock method, and (ii) shares of common stock issuable upon conversion of the 2026 Convertible Notes (as defined below in Note 8—Long-Term Debt), calculated using the if-converted method. The Company includes restricted stock unit ("RSUs") awards, performance share unit ("PSUs") awards and stock options in the calculation of diluted weighted average shares outstanding based on the number of common shares that would be issuable if the end of the period was also the end of the performance period required for the vesting of the awards. During periods in which the Company incurs a net loss, diluted weighted average shares outstanding are equal to basic weighted average shares outstanding because the effect of all equity awards is anti-dilutive.

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

	Year Ended December 31,		
	2018	**2019**	**2020**
Basic weighted average number of shares outstanding	316,036	306,400	272,433
Add: Dilutive effect of RSUs	—	—	—
Add: Dilutive effect of outstanding stock options	—	—	—
Add: Dilutive effect of PSUs	—	—	—
Add: Dilutive effect of 2026 Convertible Notes [(2)]	—	—	—
Diluted weighted average number of shares outstanding	316,036	306,400	272,433
Weighted average number of outstanding securities excluded from calculation of diluted earnings per common share [(1)]:			
RSUs	2,844	2,357	6,810
Outstanding stock options	626	527	327
PSUs	1,705	1,443	432
2026 Convertible Notes [(3)]	—	—	31,388

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

(2) In August 2020 and September 2020, the Company issued $287.5 million in aggregate principal amount of 2026 Convertible Notes (as defined below in Note 8—Long-Term Debt).

(3) On January 12, 2021, the Company completed the Equitization Transactions (defined below in Note 8—Long-Term Debt) whereby the Company issued 31.4 million shares and repurchased $150 million aggregate principal amount of the 2026 Convertible Notes. See Note 8—Long-Term Debt to the consolidated financial statements for further discussion on this transaction.

(v) Treasury Share Retirement

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 accumulated earnings. 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.

(w) Equity-Based Compensation

The Company recognizes compensation cost related to all equity-based awards in the financial statements based on their estimated grant date fair value. The Company is authorized to grant various types of equity-based compensation awards including stock options, stock appreciation rights, restricted stock awards, restricted stock 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 10—Equity-Based Compensation and Retention Awards to the consolidated financial statements for additional information regarding the Company's equity-based compensation.

(x) Recently Issued Accounting Standard

On August 5, 2020, the FASB issued Accounting Standards Update No. 2020-06, *Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*, which eliminates the cash conversion model in ASC 470-20, *Debt with Conversion and Other Options*, that require separate accounting for conversion features, and instead, allows the debt instrument and conversion features to be accounted for as a single debt instrument. The new standard becomes effective for the Company on January 1, 2022, and early adoption is permitted. The Company is evaluating its plans for adoption, including the adoption date and transition method.

Upon adoption of this new standard, the Company expects to reclassify $85 million, net of deferred income taxes and equity issuance costs, to long-term debt and deferred income tax liability, as applicable, from stockholders' equity as of December 31, 2020, which amount is subject to adjustment for any conversions or other transactions until adoption of this new standard. Additionally, annual interest expense for the 2026 Convertible Notes will be based on an effective interest rate of 4.8% as compared to 15.1% for the year ended December 31, 2020 and the weighted average diluted shares outstanding will increase from zero for the year ended December 31, 2020 to 63 million under the if-converted method after giving effect to the Equitization Transactions (defined below in Note 8—Long-Term Debt). The Company does not believe that adoption of the standard will impact its operational strategies or development prospects.

(3) Deconsolidation of Antero Midstream Partners LP

On March 12, 2019, Antero Midstream GP LP and Antero Midstream Partners completed (the "Closing") the transactions contemplated by the Simplification Agreement (the "Simplification Agreement"), dated as of October 9, 2018, by and among Antero Midstream GP LP, Antero Midstream Partners and certain of their affiliates, pursuant to which (i) Antero Midstream GP LP was converted from a limited partnership to a corporation under the laws of the State of Delaware and changed its name to Antero Midstream Corporation, and (ii) an indirect, wholly owned subsidiary of Antero Midstream Corporation was merged with and into Antero Midstream Partners, with Antero Midstream Partners surviving the merger as an indirect, wholly owned subsidiary of Antero Midstream Corporation (together, along with the other transactions contemplated by the Simplification Agreement, the "Transactions"). In connection with the Closing, Antero received $297 million in cash and 158.4 million shares of Antero Midstream Corporation common stock in consideration for 98,870,335 common units representing limited partnership interests in Antero Midstream Partners.

The Company recorded a gain on deconsolidation of $1.4 billion calculated as the sum of (i) the cash proceeds received, (ii) the fair value of the Antero Midstream Corporation common stock received at the Closing, and (iii) the elimination of the noncontrolling interest, less the carrying amount of the investment in Antero Midstream Partners. The fair value of Antero's retained equity method investment on March 13, 2019 in Antero Midstream Corporation was $2.0 billion based on the market price of the shares received on March 12, 2019. See Note 6—Equity Method Investments to the consolidated financial statements for further discussion on equity method investments.

Antero Midstream Partners' results of operations are no longer consolidated in the Company's consolidated statement of operations and comprehensive income (loss) beginning March 13, 2019. Because Antero Midstream Partners does not meet the requirements of a discontinued operation, Antero Midstream Partners' results of operations continue to be included in the Company's consolidated statement of operations and comprehensive income (loss) through March 12, 2019.

Summarized Financial Information of Antero Midstream Partners

The following table presents a summary of assets and liabilities of Antero Midstream Partners as of March 12, 2019, the date of deconsolidation.

(in thousands)	March 12, 2019
Current assets	$ 763,109
Property and equipment, net	3,003,693
Noncurrent assets	501,208
Total assets	$ 4,268,010
Current liabilities	$ 123,473
Long-term debt	2,359,084
Other noncurrent liabilities	123,523
Total liabilities	$ 2,606,080
Net assets	$ 1,661,930

(4) 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 are achieved in the third quarter of 2020 and first quarter of 2021. All cash contributed by Sixth Street at the initial closing was distributed to the Company. The Company met the applicable production threshold during the third quarter of 2020 and received a $51 million cash distribution during the year ended December 31, 2020.

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 and (b) the earlier of (i) April 1, 2023 and (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.

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

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 the Company will receive all distributions in respect of the Incremental Override, unless certain production targets are not achieved, in which case Sixth Street will receive some or all of the 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 conveyance of the ORRIs from the Company to Martica was accounted for as a transaction between entities under common control. As a result, the contributed ORRIs have been recorded by Martica at their historical cost.

(b) Volumetric Production Payment Transaction

On August 10, 2020, the Company completed a volumetric production payment transaction and received net proceeds of approximately $216 million (the "VPP"). In connection with the VPP, the Company entered into a purchase and sale agreement, together with a conveyance agreement and production and marketing agreement, with J.P. Morgan Ventures Energy Corporation ("JPM-VEC") to convey, effective July 1, 2020, an overriding royalty interest in dry gas producing properties in West Virginia (the "VPP Properties") equal to 136,589,000 MMBtu over the expected seven-year term of the VPP.

The Company has accounted for the VPP as a conveyance under ASC 932, and the net proceeds were recorded as deferred revenue in the consolidated balance sheet. Deferred revenue is recognized as volumes are delivered using the units-of-production method over the term of the VPP. Under the production and marketing agreement, Antero and its affiliates provide certain marketing services as JPM-VEC's agent, and any income or expenses related to these services will be recorded as marketing revenue or marketing expenses as appropriate.

Contemporaneously with the VPP, the Company executed a call option related to the production volumes associated with its retained interest in the VPP properties, which is collateralized by a mortgage on the VPP properties. Additionally, the production and marketing agreement contains an embedded put option related to the production volumes for the Company's retained interest in the VPP properties, which has been bifurcated from the production and marketing arrangement and accounted for as a derivative instrument recorded at fair value. See Note 12—Derivative Instruments to the consolidated financial statements for more information on the Company's derivative instruments.

(c) Subsequent Event

Drilling Partnership

On February 17, 2021, Antero Resources announced the formation of a drilling partnership with QL Capital Partners ("QL"), an affiliate of Quantum Energy Partners. Under the terms of the arrangement, QL will fund 20% of total development capital spending in 2021 and is expected to fund between 15% and 20% of total development capital spending on an annual basis from 2022 through 2024. All of the wells spud during each calendar year period will be a separate annual tranche. Capital costs in excess of, and cost savings below, a specified percentage of budgeted amounts for each annual tranche will be for Antero Resources' account.

For each tranche other than 2021, Antero Resources will propose a capital budget and estimated internal rate of return ("IRR") for all wells to be spud during the year and, subject to the mutual agreement of the parties that the estimated IRR for each tranche exceeds a specified return, QL will be obligated to participate in such tranche. For each annual tranche in which QL participates, QL will receive a proportionate working interest percentage in each well spud in such tranche. If Antero Resources presents a capital budget for an annual tranche with an estimated IRR equal to or exceeding a specified return that QL in good faith believes is less than such specified return and QL elects not to participate, Antero Resources will not be obligated to offer QL the opportunity to participate in subsequent tranches. No earlier than December 31 following the expiration of each tranche year, Antero Resources will calculate the tranche IRR for such tranche year and, if the tranche IRR exceeds certain specified returns, Antero Resources will receive a carry in the form of a one-time payment from QL for such annual tranche.

(5) Revenue

(a) Disaggregation of Revenue

Revenue is disaggregated by type in the following table. The table also identifies which reportable segment that the disaggregated revenues relate. See Note 18—Segment Information to the consolidated financial statements for more information on reportable segments.

	Year Ended December 31,			
(in thousands)	**2018**	**2019**	**2020**	**Reportable Segment**
Revenues from contracts with customers:				
Natural gas sales	$ 2,287,939	2,247,162	1,809,952	Exploration and production
Natural gas liquids sales (ethane)	172,653	124,563	113,811	Exploration and production
Natural gas liquids sales (C3+ NGLs)	1,005,124	1,094,599	1,047,872	Exploration and production
Oil sales	187,178	177,549	112,270	Exploration and production
Gathering and compression [(1)]	17,817	3,972	—	Equity method investment in Antero Midstream Corporation
Water handling and treatment [(1)]	3,527	506	—	Equity method investment in Antero Midstream Corporation
Marketing	458,901	292,207	310,572	Marketing
Total revenue from contracts with customers	4,133,139	3,940,558	3,394,477	
Income from derivatives, deferred revenue and other sources	6,487	468,132	97,222	
Total revenue	$ 4,139,626	4,408,690	3,491,699	

(1) Gathering and compression and water handling and treatment revenues were included through March 12, 2019. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for further discussion on the Transactions.

(b) Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that have a contract term greater than one year, the Company utilized the practical expedient in ASC 606, 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, 2019 and 2020, the Company's receivables from contracts with customers were $318 million and $425 million, respectively.

(6) Equity Method Investments

(a) Summary of Equity Method Investments

As of December 31, 2020, Antero owned approximately 29.2% of Antero Midstream Corporation's common stock, which is reflected in Antero's consolidated financial statements using the equity method of accounting. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for further discussion on the Transactions.

Prior to March 13, 2019, Antero's consolidated results included two equity method investments held by Antero Midstream Partners: a 15% equity interest in Stonewall Gas Gathering LLC ("Stonewall"), which operates a regional gathering pipeline on which the Company is an anchor shipper, and a 50% interest in the joint venture entered into between Antero Midstream Partners and MarkWest Energy Partners, L.P. ("MarkWest"), a wholly owned subsidiary of MPLX, LP, to develop processing and fractionation assets in Appalachia (the "Joint Venture"). Effective March 13, 2019, the equity in earnings of these investments are accounted for in the equity in earnings (loss) of Antero Midstream Corporation.

The following table is a reconciliation of investments in unconsolidated affiliates for the years ended December 31, 2019 and 2020 in thousands):

	Stonewall [1]	MarkWest Joint Venture	Antero Midstream Corporation [2]	Total
Balances as of December 31, 2018	$ 68,103	365,539	—	433,642
Investments [3]	—	25,020	—	25,020
Equity in net income (loss) of unconsolidated affiliates	1,894	10,370	(155,480)	(143,216)
Distributions/dividends from unconsolidated affiliates	(3,000)	(9,605)	(145,351)	(157,956)
Return of investment [4]	—	—	(208,745)	(208,745)
Impairment [5]	—	—	(467,590)	(467,590)
Elimination of intercompany profit	—	—	44,548	44,548
Effects of deconsolidation [6]	(66,997)	(391,324)	1,987,795	1,529,474
Balances as of December 31, 2019	—	—	1,055,177	1,055,177
Equity in loss of unconsolidated affiliates	—	—	(62,660)	(62,660)
Distributions/dividends from unconsolidated affiliates	—	—	(171,022)	(171,022)
Impairment [5]	—	—	(610,632)	(610,632)
Elimination of intercompany profit	—	—	44,219	44,219
Balances as of December 31, 2020 [7]	$ —	—	255,082	255,082

(1) Distributions are net of operating and capital requirements retained by Stonewall.
(2) As adjusted for the amortization of the difference between the cost of the equity method investment in Antero Midstream Corporation and the amount of underlying equity in the net assets of Antero Midstream Partners as of the date of deconsolidation and as adjusted for the return of investment.
(3) Investments in the Joint Venture during the year ended December 31, 2019 relate to capital contributions for construction of additional processing facilities.
(4) On December 16, 2019, Antero Midstream Corporation repurchased $100 million of its shares of common stock from the Company resulting in a return of investment. The Company recorded an $109 million loss on investment due to the carrying value exceeding the fair value of the stock repurchased.
(5) Other-than-temporary impairment of the Company's investment in Antero Midstream Corporation to reduce the carrying value of such investment to fair value, which was based on the quoted market share price of Antero Midstream Corporation as of December 31, 2019 and March 31, 2020, respectively (Level 1).
(6) Effective March 13, 2019, the equity in earnings of Stonewall and the Joint Venture are accounted for in the equity in earnings of Antero Midstream Corporation.

(7) The Company's investment in Antero Midstream Corporation as of December 31, 2020, based on the quoted market share price of Antero Midstream Corporation on such date, was $1.1 billion.

(b) Summarized Financial Information of Antero Midstream Corporation

The following tables present summarized financial information of Antero Midstream Corporation.

Balance Sheet

(in thousands)	December 31, 2019	December 31, 2020
Current assets	$ 108,558	93,931
Noncurrent assets	6,174,320	5,516,981
Total assets	$ 6,282,878	5,610,912
Current liabilities	$ 242,084	94,005
Noncurrent liabilities	2,897,380	3,098,621
Stockholders' equity	3,143,414	2,418,286
Total liabilities and stockholders' equity	$ 6,282,878	5,610,912

Statement of Operations

(in thousands)	For the period March 13, 2019 through December 31, 2019	Year Ended December 31, 2020
Revenues	$ 792,588	900,719
Operating expenses	1,177,610	1,018,357
Loss from operations	$ (385,022)	(117,638)
Loss attributable to the equity method investment	$ (341,565)	(122,527)

(7) Accrued Liabilities

Accrued liabilities as of December 31, 2019 and 2020 consisted of the following items (in thousands):

	December 31, 2019	December 31, 2020
Capital expenditures	$ 105,706	32,372
Gathering, compression, processing, and transportation expenses	134,153	152,724
Marketing expenses	52,612	68,193
Interest expense, net	30,834	25,645
Accrued taxes	39,332	40,796
Other	38,213	23,794
Total accrued liabilities	$ 400,850	343,524

(8) Long-Term Debt

Long-term debt as of December 31, 2019 and 2020 consisted of the following items (in thousands):

	December 31,	
	2019	2020
Credit Facility [(a)]	$ 552,000	1,017,000
5.375% senior notes due 2021 [(b)]	952,500	—
5.125% senior notes due 2022 [(c)]	923,041	660,516
5.625% senior notes due 2023 [(d)]	750,000	574,182
5.00% senior notes due 2025 [(e)]	600,000	590,000
4.25% convertible senior notes due 2026 [(f)]	—	287,500
Total principal	3,777,541	3,129,198
Unamortized premium (discount), net	791	(111,886)
Unamortized debt issuance costs	(19,464)	(15,719)
Long-term debt	$ 3,758,868	3,001,593

(a) Senior Secured Revolving Credit Facility

Antero Resources has a senior secured revolving credit facility (the "Credit Facility") with a consortium of bank lenders. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of Antero Resources' assets and are subject to regular semi-annual redeterminations. The borrowing base and lender commitments were each reaffirmed in the semi-annual redetermination in October 2020. The next redetermination of the borrowing base is scheduled to occur in April 2021. The Credit Facility is scheduled to mature on October 26, 2022. As of December 31, 2020, the borrowing base under the Credit Facility was $2.85 billion and lender commitments were $2.64 billion.

Antero Resources was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2019 and 2020.

As of December 31, 2020, Antero Resources had an outstanding balance under the Credit Facility of $1.0 billion with a weighted average interest rate of 3.26%, and outstanding letters of credit of $730 million. As of December 31, 2019, Antero Resources had an outstanding balance under the Credit Facility of $552 million, with a weighted average interest rate of 3.28%, and outstanding letters of credit of $623 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from (i) 0.300% to 0.375% (subject to certain exceptions) of the unused portion based on utilization.

(b) 5.375% Senior Notes Due 2021

On November 5, 2013, Antero Resources issued $1.0 billion of 5.375% senior notes due November 1, 2021 (the "2021 Notes") at par. The 2021 Notes were unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2021 Notes ranked pari passu to Antero Resources' other outstanding senior notes. The 2021 Notes were guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2021 Notes was payable on May 1 and November 1 of each year. The Company repurchased or otherwise redeemed all of the 2021 Notes from time to time during the years ended December 31, 2019 and 2020. See —Debt Repurchase Program below for further details on 2021 Notes repurchases.

(c) 5.125% Senior Notes Due 2022

On May 6, 2014, Antero Resources issued $600 million of 5.125% senior notes due December 1, 2022 (the "2022 Notes") at par. On September 18, 2014, Antero Resources issued an additional $500 million of the 2022 Notes at 100.5% of par. The 2022 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2022 Notes rank pari passu to Antero Resources' other outstanding senior notes. The 2022 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2022 Notes is payable on June 1 and December 1 of each year. Antero Resources may redeem all or part of the 2022 Notes at a redemption price of 100.00%. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2022 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 2022 Notes, plus accrued and unpaid interest.

(d) 5.625% Senior Notes Due 2023

On March 17, 2015, Antero Resources issued $750 million of 5.625% senior notes due June 1, 2023 (the "2023 Notes") at par. The 2023 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2023 Notes rank pari passu to Antero Resources' other outstanding senior notes. The 2023 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2023 Notes is payable on June 1 and December 1 of each year. Antero Resources may redeem all or part of the 2023 Notes at any time at redemption prices ranging from 101.406% to 100.00% on or after June 1, 2021. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2023 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 2023 Notes, plus accrued and unpaid interest.

(e) 5.00% Senior Notes Due 2025

On December 21, 2016, Antero Resources issued $600 million of 5.00% senior notes due March 1, 2025 (the "2025 Notes") at par. The 2025 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2025 Notes rank pari passu to Antero Resources' other outstanding senior notes. The 2025 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2025 Notes is payable on March 1 and September 1 of each year. Antero Resources may redeem all or part of the 2025 Notes at any time on or after March 1, 2020 at redemption prices ranging from 103.750% on or after March 1, 2020 to 100.00% on or after March 1, 2023. In addition, on or before March 1, 2020, Antero Resources may redeem up to 35% of the aggregate principal amount of the 2025 Notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.00% of the principal amount of the 2025 Notes, plus accrued and unpaid interest. At any time prior to March 1, 2020, Antero Resources may also redeem the 2025 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2025 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2025 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 2025 Notes, plus accrued and unpaid interest.

(f) 4.25% Convertible Senior Notes Due 2026

On August 21, 2020, Antero Resources issued $250 million in aggregate principal amount of 4.25% senior unsecured convertible notes (the "2026 Convertible Notes"). On September 2, 2020, Antero Resources issued an additional $37.5 million aggregate principal amount of 2026 Convertible Notes pursuant to the partial exercise of the initial purchasers' option to purchase additional 2026 Convertible Notes. The 2026 Convertible Notes were issued pursuant to an indenture and are senior, unsecured obligations of Antero Resources. The 2026 Convertible Notes bear interest at a fixed rate of 4.25% per annum, payable semi-annually in arrears on March 1 and September 1 of each year, commencing on March 1, 2021. Proceeds from the issuance of the 2026 Convertible Notes totaled $278.5 million, net of initial purchasers' fees and issuance cost of $9 million. Each capitalized term used in this subsection but not otherwise defined in this Annual on Form 10-K has the meaning as set forth in the indenture governing the 2026 Convertible Notes.

The initial conversion rate is 230.2026 shares of Antero Resources' common stock per $1,000 principal amount of 2026 Convertible Notes, subject to adjustment upon the occurrence of specified events. As of December 31, 2020, the if-converted value of the 2026 Convertible Notes was $361 million, which exceeded the principal amount of the 2026 Convertible Notes by $73 million. The 2026 Convertible Notes will mature on September 1, 2026, unless earlier repurchased, redeemed or converted. Before May 1, 2026, note holders will have the right to convert their 2026 Convertible Notes only upon the occurrence of the following events:

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

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

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

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

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

Upon conversion, Antero Resources may satisfy its conversion obligation by paying and/or delivering, as the case may be, cash, shares of Antero Resources' common stock or a combination of cash and shares of Antero Resources' common stock, at Antero Resources' election, in the manner and subject to the terms and conditions provided in the indenture governing the 2026 Convertible Notes. Antero Resources' current intent is is to settle the principle amount of the 2026 Convertible Notes in cash upon conversion except as it relates to the Equitization Transactions discussed in Note 8(h) below. At no point since issuance of the 2026 Convertible Notes has the conditions allowing holders of the 2026 Convertible Notes to exercise their conversion right been met.

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

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

Upon issuance, the Company separately accounted for the liability and equity components of the 2026 Convertible Notes. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the 2026 Convertible Notes and the estimated fair value of the liability component was recorded as a debt discount and will be amortized to interest expense, together with debt issuance costs, over the term of the 2026 Convertible Notes using the effective interest method, with an effective interest rate of 15.1% per annum. As of the issuance date, the fair value of the 2026 Convertible Notes was estimated at $172 million, resulting in a debt discount at inception of $116 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the 2026 Convertible Notes issuance. This equity component was recorded, net of deferred taxes and issuance costs, in additional paid-in capital within the consolidated balance sheet and statement of stockholders' equity and will not be remeasured as long as it continues to meet the conditions for equity classification.

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

The 2026 Convertible Notes consist of the following as of December 31, 2020 (in thousands):

Liability component:		
Principal	$	287,500
Less: unamortized note discount		(112,265)
Less: unamortized debt issuance costs		(5,852)
Net carrying value	$	169,383
Equity component [(1)]	$	115,601

(1) Recorded in additional paid-in capital, net of $3 million of issuance costs and $28 million of deferred taxes.

(g) Debt Repurchase Program

During the year ended December 31, 2019, Antero Resources repurchased $225 million principal amount of debt at a 17% weighted average discount, including a portion of its 2021 Notes and 2022 Notes. The Company recognized a gain of approximately $36 million on the early extinguishment of the debt repurchased.

During the year ended December 31, 2020, Antero Resources repurchased $1.4 billion aggregate principal amount of debt at a weighted average discount of 13%, which purchases included a portion of the 2021 Notes, 2022 Notes, 2023 Notes and 2025 Notes. The Company recognized a gain of approximately $176 million for the year ended December 31, 2020 on the early extinguishment of the debt repurchased. Repurchases of the principal amount of debt during year ended December 31, 2020 include repurchases of $367 million aggregate principal amount of the 2021 Notes, 2022 Notes and 2023 Notes through previously disclosed tender offers at a weighted average discount of 10%.

(h) Subsequent Events

Issuance of 8.375% Senior Notes Due 2026

On January 4, 2021, Antero Resources issued $500 million of 8.375% senior notes due July 15, 2026 (the "2026 Notes") at par. The 2026 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2026 Notes rank pari passu to Antero Resources' other outstanding senior notes. The 2026 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2026 Notes is payable on January 15 and July 15 of each year. Antero Resources may redeem all or part of the 2026 Notes at any time on or after January 15, 2024 at redemption prices ranging from 104.188% on or after January 15, 2024 to 100.00% on or after January 15, 2026. In addition, on or before January 15, 2024, Antero Resources may redeem up to 35% of the aggregate principal amount of the 2026 Notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 108.375% of the principal amount of the 2026 Notes, plus accrued and unpaid interest. At any time prior to January 15, 2024, Antero Resources may also redeem the 2026 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2026 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2026 Notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2026 Notes, plus accrued and unpaid interest.

Partial Equitization of 2026 Convertible Notes

On January 12, 2021, the Company completed a registered direct offering (the "Share Offering") of an aggregate of 31.4 million shares of its common stock at a price of $6.35 per share to certain holders of the 2026 Convertible Notes. The Company used the proceeds from the Share Offering and approximately $63 million of borrowings under the Credit Facility to repurchase from such holders $150 million aggregate principal amount of the 2026 Convertible Notes in privately negotiated transactions (the "Convertible Note Repurchase," and, collectively with the Share Offering, the "Equitization Transactions"). The 2026 Convertible Notes have an initial conversion rate of 230.2026 shares of the Company's common stock per $1,000 principal amount, and the Equitization Transactions had the effect of increasing this conversion rate to 275.3525 shares of common stock per $1,000 principal amount.

Redemption of 2022 Notes

On January 16, 2021, the Company completed a partial redemption of $350 million of the 2022 Notes at par, plus accrued and unpaid interest. On February 10, 2021, the Company redeemed $311 million of 2022 Notes that remained outstanding at par, plus accrued and unpaid interest, and as a result, the 2022 Notes were fully retired as of February 10, 2021.

Issuance of 7.625% Senior Notes Due 2029

On January 26, 2021, Antero Resources issued $700 million of 7.625% senior notes due February 1, 2029 (the "2029 Notes") at par. The 2029 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2029 Notes rank pari passu to Antero Resources' other outstanding senior notes. The 2029 Notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2029 Notes is payable on February 1 and August 1 of each year. Antero

Resources may redeem all or part of the 2029 Notes at any time on or after February 1, 2024 at redemption prices ranging from 103.813% on or after February 1, 2024 to 100.00% on or after February 1, 2027. In addition, on or before February 1, 2024, Antero Resources may redeem up to 35% of the aggregate principal amount of the 2029 Notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 107.625% of the principal amount of the 2029 Notes, plus accrued and unpaid interest. At any time prior to February 1, 2024, Antero Resources may also redeem the 2029 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2029 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2029 Notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2029 Notes, plus accrued and unpaid interest.

(9) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2019 and 2020 (in thousands):

	December 31,	
	2019	2020
Beginning balances	$ 58,979	54,845
Obligations incurred	2,312	1,814
Accretion expense	3,762	3,421
Settlement of obligations	(153)	(229)
Revisions to prior estimates	(2,537)	(5,399)
Effect of deconsolidation of Antero Midstream Partners LP (1)	(7,518)	—
Ending balances	$ 54,845	54,452

(1) Effective March 13, 2019, Antero no longer consolidates Antero Midstream Partners in its results.

Revisions to prior estimates in 2020 are primarily due to an increase in estimated well lives. Revisions to prior estimates in 2019 are primarily due to an increase in estimated abandonment costs for vertical wells. Asset retirement obligations are included in other liabilities on the Company's consolidated balance sheets.

(10) Equity-Based Compensation and Retention Awards

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

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

A total of 6,921,638 shares were available for future grant under the 2020 Plan as of December 31, 2020.

Antero Midstream Partners' general partner was authorized to grant up to 10,000,000 common units representing limited partner interests in Antero Midstream Partners under the Antero Midstream Partners LP Long-Term Incentive Plan (the "AMP Plan") to non-employee directors of its general partner and certain officers, employees, and consultants of Antero Midstream Partners and its affiliates (which includes Antero Resources). As part of the Transactions, each outstanding phantom unit award under the AMP Plan, was assumed by Antero Midstream Corporation and converted into 1.8926 RSUs under the Antero Midstream Corporation Long Term

Incentive Plan (the "AMC Plan"). Each RSU award under the AMC Plan represents a right to receive one share of Antero Midstream Corporation common stock.

The Company's equity-based compensation expense, by type of award, was as follows for the years ended December 31, 2018, 2019 and 2020 (in thousands):

	Year Ended December 31,		
	2018	2019	2020
RSU awards	$ 41,505	10,343	12,510
Stock options	1,799	355	—
PSU awards	9,659	8,069	7,219
Antero Midstream Partners phantom unit awards (1)	15,351	3,425	2,519
Equity awards issued to directors	2,100	1,367	1,069
Total expense	$ 70,414	23,559	23,317

(1) Antero Resources recognized compensation expense for equity awards granted under the 2013 Plan, 2020 Plan and the AMP Plan because the awards under the AMP Plan are accounted for as if they are distributed by Antero Midstream Partners to Antero Resources. Antero Resources allocates a portion of equity-based compensation expense related to grants prior to the Transactions to Antero Midstream Partners based on its proportionate share of Antero Resources' labor costs. Through March 12, 2019, the total amount of equity-based compensation is included in the consolidated financial statements of Antero Resources; and effective March 13, 2019 (date of deconsolidation), the amount allocated to Antero Midstream Partners is no longer reflected in Antero Resources' consolidated financial statements. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for further discussion on the Transactions.

(a) Restricted Stock Unit Awards

RSU awards vest subject to the satisfaction of service requirements. Expense related to each RSU award is recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. The grant date fair values of these awards are determined based on the closing price of Antero Resources' common stock on the date of the grant.

A summary of RSU award activity for the year ended December 31, 2020 is as follows:

	Number of Shares	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value (in thousands)
Total awarded and unvested—December 31, 2019	2,370,575	$ 12.81	$ 6,756
Granted	7,001,802	2.57	
Vested	(809,008)	15.62	
Forfeited	(130,972)	11.91	
Total awarded and unvested—December 31, 2020	8,432,397	$ 4.06	$ 45,957

Intrinsic values are based on the closing price of Antero Resources' common stock on the referenced dates. As of December 31, 2020, there was $23 million of unamortized equity-based compensation expense related to unvested restricted stock units. That expense is expected to be recognized over a weighted average period of approximately 2.2 years.

(b) Stock Options

Stock options granted under the 2013 Plan have a maximum contractual life of 10 years. Expense related to stock options is recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. Stock options were granted with an exercise price equal to or greater than the market price of Antero Resources' common stock on the dates of grant.

A summary of stock option activity for the year ended December 31, 2020 is as follows:

	Stock Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Intrinsic Value (in thousands)
Outstanding—December 31, 2019	467,633	$ 50.64	5.1	$ —
Granted	—	—		
Exercised	—	—		
Forfeited	—	—		
Expired	(35,172)	50.56		
Outstanding—December 31, 2020	432,461	$ 50.64	4.1	$ —
Vested—December 31, 2020	432,461	$ 50.64	4.1	$ —
Exercisable —December 31, 2020	432,461	$ 50.64	4.1	$ —

Intrinsic values are based on the exercise price of the options and the closing price of Antero Resources' common stock on the referenced dates.

A Black-Scholes option-pricing model is used to determine the grant-date fair value of stock options. Expected volatility was derived from the volatility of the historical stock prices of a peer group of similar publicly traded companies' stock prices as Antero Resources' common stock had traded for a relatively short period of time at the dates the options were granted. The risk-free interest rate was determined using the implied yield available for zero-coupon U.S. government issues with a remaining term approximating the expected life of the options. A dividend yield of zero was assumed.

(c) Performance Share Unit Awards

Performance Share Unit Awards Based on Stock Price Targets

In 2016, the Company granted PSUs to certain of its executive officers that are based on stock price targets. The vesting of these PSUs is conditioned on the closing price of Antero Resources' common stock achieving specific price thresholds over 10-day periods, subject to the following vesting restrictions: no PSUs may vest before the first anniversary of the grant date; no more than one-third of the PSUs may vest before the second anniversary of the grant date; and no more than two-thirds of the PSUs may vest before the third anniversary of the grant date. Any PSUs which have not vested by the fifth anniversary of the grant date will expire. Expense related to these PSUs is recognized on a graded basis over three years. 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 Total Shareholder Return ("TSR")

In 2016 and 2017, the Company granted PSUs to certain of its employees and executive officers that vest based on the TSR of Antero Resources' common stock relative to the TSR of a peer group of companies over a three-year performance period. The number of shares of common stock which may ultimately be earned ranges from zero to 200% of the PSUs granted. Expense related to these PSUs is recognized on a straight-line basis over three years. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period.

In 2019, the Company granted PSUs to certain of its employees and executive officers that vest based on Antero Resources' absolute TSR, with target payout achieved if the price per share of Antero Resources' common stock reaches 125% of the beginning price (as defined in the award agreement) at the end of a three-year performance period. The number of shares of common stock which may ultimately be earned ranges from zero to 200% of the PSUs granted. Expense related to these PSUs is recognized on a straight-line basis over three years. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period.

In 2020, 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, 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. The number of shares of common stock that may ultimately be earned following the end of the cumulative three-year performance period ranges from zero to 150% of the target number of PSUs granted. Expense related to these PSUs is recognized on a graded-vested basis over approximately three years. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period.

Additionally, in 2020, the Company granted PSUs to certain of its executive officers that vest 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. The number of shares of common stock that may ultimately be earned following the end of the cumulative three-year performance period ranges from zero to 150% of the target number of PSUs granted. Expense related to these PSUs is recognized on a graded-vested basis over approximately three years. 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 TSR and Return on Capital Employed ("ROCE")

In 2018, the Company granted PSUs to certain of its employees and executive officers, a portion of which vest based on the Company's absolute TSR, with target payout achieved if the price per share of Antero Resources' common stock reaches 125% of the beginning price (as defined in the award agreement) at the end of a three-year performance period ("2018 TSR PSUs"). The number of awards actually earned with respect to the 2018 TSR PSUs will be subject to further adjustment based on the TSR of Antero Resources' common stock relative to the TSR of a peer group of companies over the same period. The number of shares of common stock that may ultimately be earned with respect to the 2018 TSR PSUs ranges from zero to 200% of the target number of 2018 TSR PSUs originally granted. Expense related to the 2018 TSR PSUs is recognized on a straight-line basis over three years. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period.

The other portion of the PSUs granted in 2018 vest based on the Company's actual ROCE (as defined in the award agreement) over a three-year period as compared to a targeted ROCE ("ROCE PSUs"). The number of shares of common stock that may ultimately be earned with respect to the ROCE PSUs ranges from zero to 200% of the target number of ROCE PSUs originally granted. Expense related to the ROCE PSUs is recognized based on the number of shares of common stock that are expected to be issued at the end of the measurement period, and is reversed if the likelihood of achieving the performance condition decreases. As of December 31, 2019, the likelihood of achieving the performance conditions related to the ROCE PSUs decreased to a level below probable and therefore, expense has not been recognized in the current year and will not be recognized unless the likelihood of achieving the performance condition becomes probable.

Summary Information for Performance Share Unit Awards

A summary of PSU activity for the year ended December 31, 2020 is as follows:

	Number of Units	Weighted Average Grant Date Fair Value
Total awarded and unvested—December 31, 2019	2,537,283	$ 16.74
Granted	469,000	2.97
Forfeited	(29,316)	12.21
Cancelled (unearned)	(429,169)	26.21
Total awarded and unvested—December 31, 2020	2,547,798	$ 12.66

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 ROCE-based PSUs is based on the closing price of Antero Resources' common stock on the date of the grant, assuming the achievement of the performance condition.

The following table presents information regarding the weighted average fair values for market-based PSUs granted during the years ended December 31, 2018, 2019 and 2020, and the assumptions used to determine the fair values:

	Year Ended December 31,		
	2018	2019	2020
Dividend yield	— %	— %	— %
Volatility	41 %	36 %	80 %
Risk-free interest rate	2.49 %	2.35 %	0.17 %
Weighted average fair value of awards granted—Absolute TSR	$ 24.85	9.26	2.63
Weighted average fair value of awards granted—Relative TSR	$ —	—	3.30

As of December 31, 2020, there was $8 million of unamortized equity-based compensation expense related to unvested PSUs. That expense is expected to be recognized over a weighted average period of approximately 1.2 years.

(d) Cash Retention Awards

In January 2020, the Company granted cash awards of approximately $3.3 million to certain executives under the 2013 Plan, and compensation expense for these awards is recognized ratably over the vesting period for each of three tranches through January 20, 2023. In July 2020, the Company granted additional cash awards on the aggregate of $2.6 million to certain non-executive employees under the 2020 Plan that vest ratably over four years. As of December 31, 2020, the Company has accrued approximately $3.2 million in Other liabilities in the consolidated balance sheet related to cash awards.

(e) Antero Midstream Corporation Restricted Stock Unit Awards

Phantom units granted by Antero Midstream Partners vested subject to the satisfaction of service requirements, upon the completion of which common units in Antero Midstream Partners were delivered to the holder of the phantom units. Phantom units also contained distribution equivalent rights which entitled the holder of vested common units to receive a “catch up” payment equal to common unit distributions paid by Antero Midstream Partners during the vesting period of the phantom unit award. These phantom units were treated, for accounting purposes, as if Antero Midstream Partners distributed the units to Antero Resources. Antero Resources recognized compensation expense as the units were granted to its employees, and a portion of the expense is allocated to Antero Midstream Partners. Expense related to each phantom unit award was recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures were accounted for as they occurred by reversing the expense previously recognized for awards that were forfeited during the period. The grant date fair values of these awards were determined based on the closing price of Antero Midstream Partners’ common units on the date of grant.

In connection with the closing of the Transactions, the Board of Directors of Antero Midstream Corporation adopted the AMC Plan. In accordance with the terms of the Transactions, each outstanding phantom unit under the AMP Plan was assumed by Antero Midstream Corporation and converted into 1.8926 restricted stock units under the AMC Plan.

A summary of Antero Midstream Corporation RSU awards for the year ended December 31, 2020 is as follows:

	Number of Units	Weighted Average Grant Date Fair Value	Aggregate Intrinsic Value (in thousands)
Total awarded and unvested—December 31, 2019	657,757	$ 14.71	$ 4,992
Granted	—	—	
Vested	(338,412)	14.44	
Forfeited	(22,955)	14.08	
Total awarded and unvested—December 31, 2020	296,390	$ 15.06	$ 2,285

Intrinsic values are based on the closing price of shares of Antero Midstream Corporation’s common stock or Antero Midstream Partners’ common units, as applicable, on the referenced dates. As of December 31, 2020, there was $2.2 million of unamortized equity-based compensation expense related to unvested phantom unit awards. That expense is expected to be recognized over a weighted average period of approximately 1.0 years, and the Company’s proportionate share will be allocated to it as it is recognized.

(11) Fair Value

The carrying values of accounts receivable and accounts payable as of December 31, 2019 and 2020 approximated market values because of their short-term nature. The carrying values of the amounts outstanding under the Credit Facility as of December 31, 2019 and 2020 approximated fair value because the variable interest rates are reflective of current market conditions.

The fair value and carrying value of the senior notes and 2026 Convertible Notes as of December 31, 2019 and 2020 are as follows (in thousands):

	December 31, 2019		December 31, 2020	
	Fair Value (1)	Carrying Value (2)	Fair Value (1)	Carrying Value (2)
5.375% senior notes due 2021	$ 906,304	948,904	—	—
5.125% senior notes due 2022	823,906	918,640	658,468	658,400
5.625% senior notes due 2023	602,550	744,938	562,698	571,370
5.00% senior notes due 2025	450,600	594,386	560,500	585,440
4.25% convertible senior notes due 2026 (3)	—	—	430,963	169,383
Total	$ 2,783,360	3,206,868	2,212,629	1,984,593

(1) Fair values are based on Level 2 market data inputs.
(2) Carrying values are presented net of unamortized debt issuance costs and debt discounts or premiums.
(3) Carrying value excludes the equity component of $116 million recorded to additional paid-in-capital for the 2026 Convertible Notes.

See Note 12—Derivative Instruments to the consolidated financial statements for information regarding the fair value of derivative financial instruments.

(12) Derivative Instruments

The Company is exposed to certain risks relating to its ongoing business operations, and it uses derivative instruments to manage its commodity price risk. In addition, the Company periodically enters into contracts that contain embedded features that are required to be bifurcated and accounted for separately as derivatives.

(a) Commodity Derivative Positions

The Company periodically enters into natural gas, NGLs, and oil derivative contracts with counterparties to hedge the price risk associated with its production. These derivatives are not entered into for trading purposes. To the extent that changes occur in the market prices of natural gas, NGLs, and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas, NGLs, and oil recognized upon the ultimate sale of the Company's production.

The Company was party to various fixed price commodity swap contracts that settled during the years ended December 31, 2018, 2019 and 2020. The Company enters into these swap contracts when management believes that favorable future sales prices for the Company's production can be secured. Under these swap agreements, when actual commodity prices upon settlement exceed the fixed price provided by the swap contracts, the Company pays the difference to the counterparty. When actual commodity prices upon settlement are less than the contractually provided fixed price, the Company receives the difference from the counterparty. In addition, the Company has entered into basis swap contracts in order to hedge the difference between the New York Mercantile Exchange ("NYMEX") index price and a local index price.

The Company also entered into NGL derivative contracts, which establish a contractual price for the settlement month as a fixed percentage of the West Texas Intermediate Crude Oil index ("WTI") price for the settlement month. When the percentage of the contractual price is above the contracted percentage, the Company pays the difference to the counterparty. When it is below the contracted percentage, the Company receives the difference from 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.

As of December 31, 2020, the Company's fixed price natural gas, oil and NGL swap positions from January 1, 2021 through December 31, 2023 were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Weighted Average Price
Natural Gas			
January-December 2021	Henry Hub	2,160,000 MMBtu/day	$ 2.77 /MMBtu
January-December 2022	Henry Hub	1,155,486 MMBtu/day	2.50 /MMBtu
January-December 2023	Henry Hub	43,000 MMBtu/day	2.37 /MMBtu
OPIS Ethane Mt Belv			
January-March 2021	Mont Belvieu Purity Ethane-OPIS	19,000 Bbl/day	$ 8.40 /Bbl
Oil			
January-December 2021	West Texas Intermediate	3,000 Bbl/day	$ 55.16 /Bbl

In addition, the Company has a call option agreement, which entitles the holder the right, but not the obligation, to enter into a fixed price swap agreement on December 21, 2023 to purchase 427,500 MMBtu per day at a price of $2.77 per MMBtu for the year ending December 31, 2024.

As of December 31, 2020, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of the Columbia Gas Transmission pipeline ("TCO") to the NYMEX Henry Hub natural gas price, were as follows:

Commodity / Settlement Period	Index to Basis Differential	Contracted Volume	Weighted Average Hedged Differential
Natural Gas			
January-December 2021	NYMEX to TCO	40,000 MMBtu/day	$ 0.414 /MMBtu
January-December 2022	NYMEX to TCO	60,000 MMBtu/day	0.515 /MMBtu
January-December 2023	NYMEX to TCO	50,000 MMBtu/day	0.525 /MMBtu
January-December 2024	NYMEX to TCO	50,000 MMBtu/day	0.530 /MMBtu

As of December 31, 2020, the Company had natural gas and NGL contracts for January 1, 2021 through December 31, 2021 that fix the Mont Belvieu index price to percentages of WTI as follows:

Commodity / Settlement Period	Index to Basis Differential	Contracted Volume	Weighted Average Payout Ratio
Gas Liquids			
January-December 2021	Mont Belvieu Natural Gasoline to WTI	9,325 Bbl/day	78 %

As of December 31, 2020, the Company's fixed price natural gas, oil and NGL swap positions from January 1, 2021 through March 31, 2025 for Martica, the Company's consolidated VIE, were as follows:

Commodity / Settlement Period	Index	Contracted Volume	Weighted Average Price
Natural Gas			
January-December 2021	Henry Hub	46,536 MMBtu/day	$ 2.62 /MMBtu
January-December 2022	Henry Hub	38,356 MMBtu/day	2.39 /MMBtu
January-December 2023	Henry Hub	35,615 MMBtu/day	2.35 /MMBtu
January-December 2024	Henry Hub	23,885 MMBtu/day	2.33 /MMBtu
January-March 2025	Henry Hub	18,021 MMBtu/day	2.53 /MMBtu
OPIS Propane Mt Belv Non-TET			
January-December 2021	Mont Belvieu Propane-OPIS	1,121 Bbl/day	$ 18.90 /Bbl
January-December 2022	Mont Belvieu Propane-OPIS	934 Bbl/day	19.32 /Bbl
OPIS Natural Gasoline Mt Belv Non-TET			
January-December 2021	Mont Belvieu Natural Gasoline-OPIS	282 Bbl/day	$ 29.82 /Bbl
January-December 2022	Mont Belvieu Natural Gasoline-OPIS	282 Bbl/day	34.44 /Bbl
OPIS Ethane Mt Belv			
January-December 2021	Mont Belvieu Purity Ethane-OPIS	987 Bbl/day	$ 7.14 /Bbl
January-March 2022	Mont Belvieu Purity Ethane-OPIS	521 Bbl/day	6.72 /Bbl
Oil			
January-December 2021	West Texas Intermediate	117 Bbl/day	$ 39.94 /Bbl
January-December 2022	West Texas Intermediate	71 Bbl/day	41.09 /Bbl
January-December 2023	West Texas Intermediate	52 Bbl/day	42.45 /Bbl
January-December 2024	West Texas Intermediate	43 Bbl/day	44.02 /Bbl
January-March 2025	West Texas Intermediate	39 Bbl/day	45.06 /Bbl

(b) Embedded Derivatives

The VPP includes an embedded put option tied to NYMEX pricing for the production volumes associated with the Company's retained interest in the VPP properties of 111,743,000 MMBtu remaining through December 31, 2026 at a weighted average strike price of $2.60 per MMBtu. The embedded put option is not clearly and closely related to the host contract, and therefore, the Company bifurcated this derivative instrument and reflected it at fair value in the consolidated financial statements.

(c) Marketing Derivatives

In 2017, due to delay of the in-service date for a pipeline on which the Company is to be an anchor shipper, the Company realized it would not be able to fulfill its delivery obligations under a 2018 natural gas sales contract. In order to acquire gas to fulfill its delivery obligations, the Company entered into several natural gas purchase agreements with index-based pricing to purchase gas for resale under this sales contract. Subsequently, the Company and the counterparty to the sales contract came to an agreement that the Company's delivery obligations under the contract would not begin until the earlier of (1) the in-service date of the pipeline and (2) January 1, 2019. Consequently, in December 2017, the Company entered into natural gas sales agreements with index-based pricing to resell the purchased gas for delivery during the period from February to October 2018. The natural gas that it had purchased for January was sold on the spot market during January 2018.

The Company determined that these gas purchase and sales agreements should be accounted for as derivatives and measured at fair value at the end of each period. For the year ended December 31, 2018, the Company recognized a fair value gain of $94 million and realized proceeds of $73 million. There were no marketing derivative fair value gains or losses for the years ended December 31, 2019 and 2020.

(d) Summary

The following table presents a summary of the fair values of the Company's derivative instruments and where such values are recorded in the consolidated balance sheets as of December 31, 2019 and 2020. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	Balance Sheet Location	December 31, 2019	December 31, 2020
Asset derivatives not designated as hedges for accounting purposes:			
Commodity derivatives—current	Derivative instruments	$ 422,849	97,144
Embedded derivatives—current	Derivative instruments	—	7,986
Commodity derivatives—noncurrent	Derivative instruments	333,174	14,689
Embedded derivatives—noncurrent	Derivative instruments	—	32,604
Total asset derivatives		756,023	152,423
Liability derivatives not designated as hedges for accounting purposes:			
Commodity derivatives—current (1)	Derivative instruments	6,721	31,242
Commodity derivatives—noncurrent (1)	Derivative instruments	3,519	99,172
Total liability derivatives		10,240	130,414
Net derivatives assets		$ 745,783	22,009

(1) As of December 31, 2020, approximately $14 million of commodity derivative liabilities, including $7 million of current commodity derivatives and $7 million of noncurrent commodity derivatives, are attributable to the Company's consolidated VIE, Martica.

The following table presents 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, 2019			December 31, 2020		
	Gross Amounts on Balance Sheet	Gross Amounts Offset on Balance Sheet	Net Amounts of Assets (Liabilities) on Balance Sheet	Gross Amounts on Balance Sheet	Gross Amounts Offset on Balance Sheet	Net Amounts of Assets (Liabilities) on Balance Sheet
Commodity derivative assets	$ 882,817	(126,794)	756,023	$ 181,375	(69,542)	111,833
Embedded derivative assets	$ —	—	—	$ 40,590	—	40,590
Commodity derivative liabilities	$ (137,034)	126,794	(10,240)	$ (199,956)	69,542	(130,414)

The following is a summary of derivative fair value gains and losses and where such values are recorded in the consolidated statements of operations for the years ended December 31, 2018, 2019 and 2020 (in thousands):

	Statement of Operations Location		Year Ended December 31,		
			2018	2019	2020
Commodity derivative fair value gains (losses)	Revenue	$	(87,594)	463,972	40,565
Embedded derivative fair value gains (losses)	Revenue	$	—	—	39,353

Commodity derivative fair value gains (losses) for the years ended December 31, 2018 and 2020, include gains of $370 million and $9 million, respectively, related to certain natural gas derivatives that were monetized prior to their contractual settlement dates. Proceeds received from the monetizations are classified as operating cash flows on the Company's consolidated statement of cash flows for the years ended December 31, 2018 and 2020. There were no commodity derivatives monetizations in the year ended December 31, 2019.

The 2018 monetizations were affected by the early settlement of April through December 2019 swaps and reducing the average fixed index prices on certain natural gas swap contracts maturing in 2020 while maintaining the total volumes hedged. The April through December 2019 swaps were replaced with collar agreements for which the Company paid a $13 million premium.

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

The Company's commodity derivative position presented in Note 12(a) above reflects the volume and adjusted fixed price indices after the 2020 monetization.

(13) Leases

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases*, which requires lessees to record lease liabilities and right-of-use assets as of the date of adoption and was incorporated into GAAP as ASC Topic 842, *Leases*. The new lease standard does not substantially change accounting by lessors. The Company adopted the new standard effective January 1, 2019. The Company is a lessee to both operating and finance lease arrangements. The standard resulted in an increase in assets and liabilities related to the Company's operating 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 are 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 elected the effective date method for adoption of the new leasing standard. This method allows the Company to not make retrospective adjustments for leases that were in effect prior to the adoption date of January 1, 2019 when disclosing comparable prior periods, but instead, account for the prior period leases under ASC Topic 840, which was the guidance in place at the time of the original reporting.

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 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.

Supplemental Balance Sheet Information Related to Leases

The Company's lease assets and liabilities as of December 31, 2019 and 2020 consisted of the following items (in thousands):

Leases	Balance Sheet Classification	December 31, 2019	December 31, 2020
Operating Leases			
Operating lease right-of-use assets:			
Processing plants	Operating lease right-of-use assets	$ 1,460,770	1,302,290
Drilling rigs and completion services	Operating lease right-of-use assets	71,662	29,894
Gas gathering lines and compressor stations (1)	Operating lease right-of-use assets	1,308,428	1,241,090
Office space	Operating lease right-of-use assets	40,491	36,879
Vehicles	Operating lease right-of-use assets	4,983	2,704
Other office and field equipment	Operating lease right-of-use assets	166	746
Total operating lease right-of-use assets		$ 2,886,500	2,613,603
Short-term operating lease obligation	Short-term lease liabilities	$ 304,397	265,178
Long-term operating lease obligation	Long-term lease liabilities	2,582,103	2,348,425
Total operating lease obligation		$ 2,886,500	2,613,603
Finance Leases			
Finance lease right-of-use assets:			
Vehicles	Other property and equipment	$ 2,328	1,206
Other office and field equipment	Other property and equipment	170	—
Total finance lease right-of-use assets (2)		$ 2,498	1,206
Short-term finance lease obligation	Short-term lease liabilities	$ 923	845
Long-term finance lease obligation	Long-term lease liabilities	1,575	361
Total finance lease obligation		$ 2,498	1,206

(1) Gas gathering lines and compressor stations leases includes $1.1 billion related to Antero Midstream Corporation as of December 31, 2019 and 2020. See "—Related party lease disclosure" for additional discussion.

(2) Financing lease assets are recorded net of accumulated amortization of $9 million and $3 million as of December 31, 2019 and 2020, respectively.

The processing plants, gathering lines and compressor stations that are classified as lease liabilities are classified as such under ASC Topic 842, *Leases*, because Antero is the sole customer of the assets and because Antero makes the decisions that most impact the economic performance of the assets.

Supplemental Information Related to Leases

Costs associated with operating leases were included in the consolidated statement of operations and comprehensive loss for the years ended December 31, 2019 and 2020 (in thousands):

Cost	Classification	Location	Year Ended December 31, 2019	Year Ended December 31, 2020
Operating lease cost	Statement of operations	Gathering, compression, processing, and transportation	$ 842,440	1,498,221
Operating lease cost	Statement of operations	General and administrative	11,228	11,530
Operating lease cost	Statement of operations	Contract termination and rig stacking	10,692	8,528
Operating lease cost	Balance sheet	Proved properties [1]	194,522	104,146
Total operating lease cost			$ 1,058,882	1,622,425
Finance lease cost:				
Amortization of right-of-use assets	Statement of operations	Depletion, depreciation, and amortization	$ 1,471	872
Interest on lease liabilities	Statement of operations	Interest expense	335	208
Total finance lease cost			$ 1,806	1,080
Short-term lease payments			$ 162,654	122,577

(1) Capitalized costs related to drilling and completion activities.

Supplemental Cash Flow Information Related to Leases

The following is the Company's supplemental cash flow information related to leases for years ended December 31, 2019 and 2020 (in thousands):

	Year Ended December 31, 2019	Year Ended December 31, 2020
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	$ 809,667	1,576,984
Operating cash flows from finance leases	335	208
Investing cash flows from operating leases	178,898	106,867
Financing cash flows from finance leases	2,507	1,291
Noncash activities:		
ROU assets obtained in exchange for new operating lease obligations	$ 3,720,945	202,125

Maturities of Lease Liabilities

The table below is a schedule of future minimum payments for operating and financing lease liabilities as of December 31, 2020 (in thousands):

(in thousands)	Operating Leases	Financing Leases	Total
2021	$ 611,093	901	611,994
2022	579,079	366	579,445
2023	575,228	8	575,236
2024	566,461	—	566,461
2025	493,783	—	493,783
Thereafter	1,558,470	—	1,558,470
Total lease payments	4,384,114	1,275	4,385,389
Less: imputed interest	(1,770,511)	(69)	(1,770,580)
Total	$ 2,613,603	1,206	2,614,809

Lease Term and Discount Rate

The table below is the Company's weighted-average remaining lease term and discount rate as of December 31, 2020:

	December 31, 2020	
	Operating Leases	**Finance Leases**
Weighted-average remaining lease term	8.0 years	1.5 years
Weighted-average discount rate	13.7 %	6.2 %

Related Party Lease Disclosure

The Company has a gathering and compression agreement with Antero Midstream Corporation, whereby Antero Midstream Corporation receives a low-pressure gathering fee per Mcf, a high-pressure gathering fee per Mcf, and a compression fee per Mcf, in each case subject to adjustments based on the consumer price index. If and to the extent the Company requests that Antero Midstream Corporation construct new high pressure lines and compressor stations, the gathering and compression agreement contains minimum volume commitments that require Antero Resources to utilize or pay for 75% of the gathering capacity and 70% of the compression capacity of such new construction for 10 years.

In December 2019, the Company and Antero Midstream Corporation agreed to extend the initial term of the gathering and compression agreement to 2038 and established a growth incentive fee program whereby low-pressure gathering fees will be reduced from 2020 through 2023 to the extent the Company achieves certain volumetric targets at certain points during such time. Upon completion of the initial contract term, the gathering and compression agreement will continue in effect from year to year until such time as the agreement is terminated, effective upon an anniversary of the effective date of the agreement, by either the Company or Antero Midstream Corporation on or before the 180th day prior to the anniversary of such effective date. The Company achieved the volumetric targets during each quarter during the year ended December 31, 2020. Antero Midstream Corporation has provided rebates of $48 million for the year ended December 31, 2020.

For the years ended December 31, 2019 and 2020, gathering and compression fees paid by Antero related to this agreement were $643 million and $679 million, respectively. As of December 31, 2019 and 2020, $57 million and $55 million was included within Accounts payable, related parties, respectively, on the consolidated balance sheet as due to Antero Midstream Corporation related to this agreement.

(14) Income Taxes

For the years ended December 31, 2018, 2019 and 2020, income tax benefit consisted of the following (in thousands):

	Year Ended December 31,		
	2018	**2019**	**2020**
Federal income tax expense (benefit)	$ —	5,048	(209)
State income tax expense (benefit), net of federal benefit	(128,857)	(79,158)	(397,273)
Total income tax benefit	$ (128,857)	(74,110)	(397,482)

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 the years ended December 31, 2018, 2019 and 2020 to income or loss before taxes as a result of the following (in thousands):

	Year Ended December 31,		
	2018	2019	2020
Federal income tax expense (benefit)	$ (36,657)	(77,122)	(348,158)
State income tax expense (benefit), net of federal benefit	(12,627)	(8,826)	(50,584)
Change in state tax rate, net of federal effect	(40,415)	24,041	2,291
Nondeductible equity-based compensation	6,079	6,920	4,490
Dividends received deduction	—	(4,201)	(4,013)
Noncontrolling interest	(73,881)	(10,998)	(1,801)
Deconsolidation adjustment	—	(6,626)	—
Change in valuation allowance	28,116	1,325	789
Other	528	1,377	(496)
Total income tax benefit	$ (128,857)	(74,110)	(397,482)

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 net deferred tax assets and liabilities as of December 31, 2019 and 2020 is as follows (in thousands):

	December 31,	
	2019	2020
Deferred tax assets:		
NOL carryforwards	$ 560,136	565,433
Equity-based compensation	7,669	8,445
Investment in Antero Midstream	172,460	330,301
Other	15,754	17,206
Total deferred tax assets	756,019	921,385
Valuation allowance	(46,802)	(46,013)
Net deferred tax assets	709,217	875,372
Deferred tax liabilities:		
Unrealized gains on derivative instruments	206,677	13,189
Oil and gas properties	1,284,528	1,188,599
Investment in Martica	—	59,586
2026 Convertible Notes	—	26,250
Total deferred tax liabilities	1,491,205	1,287,624
Net deferred tax liabilities	$ (781,988)	(412,252)

In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred 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 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 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 $47 million and $46 million as of December 31, 2019 and 2020, respectively. The valuation allowance for each of the years ended December 31, 2019 and 2020, relates to Colorado and Oklahoma state NOL carryforwards and is primarily the result of expected future reduced income tax apportionment in those states. The amount of the deferred tax asset considered realizable could be further reduced in the near term if estimates of future taxable income during the carryforward period are revised.

The calculation of the Company’s tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The Company monitors potential uncertain tax positions but does not anticipate any changes in 2021. The Company has no unrecognized tax benefit balances through December 31, 2020.

As of December 31, 2020, the Company has U.S. federal and state NOL carryforwards of $2.3 billion and $2.0 billion, respectively, exclusive of the valuation allowances discussed above. The U.S. federal and West Virginia NOL carryforwards generated in tax years prior to 2018 expire between 2032 and 2037. The Colorado NOL carryforwards generated in tax years prior to 2018 expire between 2025 and 2037. For tax years 2018 and thereafter, NOL carryforwards generated in these jurisdictions have no expiration date. The Pennsylvania NOL carryforwards expire between 2037 and 2040.

Tax years 2017 through 2020 remain open to examination by the U.S. Internal Revenue Service. The Company and its subsidiaries file tax returns with various state taxing authorities and those returns remain open to examination for tax years 2016 through 2020.

(15) Commitments

The table below is a schedule of future minimum payments for firm transportation, drilling rig and completion services, processing, gathering and compression, and office and equipment agreements, which include leases that have remaining lease terms in excess of one year as of December 31, 2020 (in thousands).

	Firm Transportation (a)	Processing, Gathering and Compression (b)	Land Payment Obligations (c)	Operating and Financing Leases (d)	Imputed Interest for Leases (d)	Total
2021	$ 1,080,150	54,873	2,859	265,849	346,145	1,749,876
2022	1,037,503	52,265	328	267,888	311,557	1,669,541
2023	1,064,981	59,140	—	300,971	274,265	1,699,357
2024	1,024,833	59,262	—	334,694	231,767	1,650,556
2025	984,743	47,960	—	306,918	186,865	1,526,486
Thereafter	6,947,951	113,379	—	1,138,489	419,981	8,619,800
Total	$ 12,140,161	386,879	3,187	2,614,809	1,770,580	16,915,616

(a) Firm Transportation

The Company has entered into firm transportation agreements with various pipelines in order to facilitate the delivery of its production to market. These contracts commit the Company to transport minimum daily natural gas or NGLs volumes at negotiated rates, or pay for any deficiencies at specified reservation fee rates. The amounts in this table are based on the Company's minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(b) Processing, Gathering, and Compression Service Commitments

The Company has entered into various long-term gas processing, gathering and compression 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) Land Payment Obligations

The Company has entered into various land acquisition 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.

(d) Leases, including imputed interest

The Company has obligations under contracts for services provided by drilling rigs and completion fleets, processing, gathering, and compression services agreements, and office and equipment leases. The values in the table represent the gross amounts that Antero Resources is committed to pay; however, the Company will record in its financial statements its proportionate share of costs based on its working interests. See Note 13—Leases to the consolidated financial statements for more information on the Company's operating and finance leases.

(e) Contract Terminations and Rig Stacking

The Company incurs costs associated with the delay or cancellation of drilling and completion contracts with third-party contractors. These costs are recorded in Contract termination and rig stacking and included in the statement of operations and comprehensive income (loss) for the years ended December 31, 2018, 2019 and 2020 (in thousands):

	Year Ended December 31,		
	2018	**2019**	**2020**
Contract termination and rig stacking	$ —	14,026	14,290

(16) Contingencies

Environmental

In June 2018, the Company received a Notice of Violation ("NOV") from the U.S. Environmental Protection Agency ("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 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 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 EPA overall 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.

SJGC

In March 2015 and December 2017, the Company filed lawsuits against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively, "SJGC") in United States District Court in Colorado seeking relief for breach of contracts and damages for amounts that SJGC short paid the Company. The contractual price for gas was based on specified indices in the contracts and SJGC began short paying the Company based on price indices unilaterally selected by SJGC and not the applicable index specified in the contracts. On May 8, 2017, a jury in the United States District Court in Colorado returned a unanimous verdict finding in favor of Antero Resources' positions in the initial lawsuit against SJGC and the Tenth Circuit Court of Appeals affirmed the judgment of the trial court. SJGC declined further appeal and stipulated to the liability in the second suit. During the year ended December 31, 2019, the Company and its royalty owners received a gross settlement of $82 million from SJGC, which was in full satisfaction and discharge of judgments entered in favor of the Company in the above described lawsuits.

WGL

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively, "WGL") were involved in multiple contractual disputes involving firm gas sales contracts executed June 20, 2014 (the "Contracts") that the Company began delivering gas under in January 2016. In late 2015, WGL asserted that the natural gas index price specified in the Contracts was no longer appropriate and sought to invoke an alternative index clause in the Contracts. This dispute was referred to arbitration. In January 2017, the arbitration panel ruled in the Company's favor and found that the natural gas index price specified in the Contracts should remain.

In March of 2017, WGL filed a lawsuit against the Company in Colorado district court claiming that the Company breached contractual obligations by failing to deliver "TCO pool" gas, ultimately seeking damages of more than $40 million. Subsequently, after WGL failed to take certain volumes of gas required under the Contracts, the Company filed a separate lawsuit against WGL to recover damages that WGL refused to pay. These two lawsuits were consolidated and tried in June 2019. On June 20, 2019, the Company was awarded a jury verdict of approximately $96 million in damages against WGL. In addition, the jury rejected WGL's claim against the Company, finding that the Company did not breach the Contracts. On December 10, 2020, the Colorado Court of Appeals affirmed the judgment of the trial court in favor of the Company. In February 2021, the Company and its royalty owners received a gross payment of approximately $107 million from WGL, which was in full satisfaction and discharge of the June 2019 judgment entered in favor of the Company.

Other

The Company is party to various other legal proceedings and claims in the ordinary course of its business. The Company believes that certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

(17) Related Parties

Antero Midstream Partners' operations comprised substantially all of the operations reflected in the gathering and processing, and water handling and treatment, results through March 12, 2019. Effective March 13, 2019, Antero Resources accounts for Antero Midstream Corporation as an equity method investment. See Note 3—Deconsolidation of Antero Midstream Partners LP to the consolidated financial statements for more discussion on the Transactions.

Substantially all of the revenues for Antero Midstream Partners or Antero Midstream Corporation were and are derived from transactions with Antero Resources. See Note 18—Segment Information to the consolidated financial statements for the operating results of the Company's reportable segments.

(18) Segment Information

See Note 2(t)—Summary of Significant Accounting Policies—Industry Segments and Geographic Information to the consolidated financial statements for a description of the Company's determination of its reportable segments. Revenues from midstream services were primarily derived from intersegment transactions for services provided to the Company's exploration and production operations prior to the closing of the Transactions. Through March 12, 2019, Antero Resources included the results of Antero Midstream Partners in its consolidated financial statements. Effective March 13, 2019, Antero no longer consolidates the results of Antero Midstream in its results; however, the Company's segment disclosures include the results of the Company's unconsolidated affiliates due to their significance to the Company's operations. See Note 3—Deconsolidation of Antero Midstream

Partners LP to the consolidated financial statements for further discussion on the Transactions. 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.

Operating segments are evaluated based on their contribution to consolidated results, which is primarily determined by the respective operating income (loss) of 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, 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.

The operating results and assets of the Company's reportable segments were as follows for the years ended December 31, 2018, 2019 and 2020 (in thousands):

	Exploration and Production	Marketing	Midstream Services	Elimination of Intersegment Transactions	Consolidated Total
Year Ended December 31, 2018					
Sales and revenues:					
Third-party	$ 3,565,300	552,982	21,344	—	4,139,626
Intersegment	(87,472)	—	1,007,178	(919,706)	—
Total	$ 3,477,828	552,982	1,028,522	(919,706)	4,139,626
Operating expenses:					
Lease operating	$ 142,234	—	262,704	(268,785)	136,153
Gathering, compression, processing, and transportation	1,792,898	—	49,550	(503,090)	1,339,358
Impairment of oil and gas properties	549,437	—	—	—	549,437
Impairment of midstream assets	—	—	9,658	—	9,658
Depletion, depreciation, and amortization	841,645	—	130,820	—	972,465
General and administrative	181,305	—	61,629	(2,590)	240,344
Other	129,947	686,055	(88,715)	93,019	820,306
Total	3,637,466	686,055	425,646	(681,446)	4,067,721
Operating income (loss)	$ (159,638)	(133,073)	602,876	(238,260)	71,905
Equity in earnings of unconsolidated affiliates	$ —	—	40,280	—	40,280
Segment assets	$ 12,986,945	34,499	3,542,862	(1,044,842)	15,519,464
Capital expenditures for segment assets	$ 1,923,488	—	542,112	(255,014)	2,210,586

	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream Corporation [1]	Elimination of Intersegment Transactions and Unconsolidated Affiliates	Consolidated Total
Year Ended December 31, 2019					
Sales and revenues:					
Third-party	$ 4,107,845	292,207	50	—	4,400,102
Intersegment	5,812	—	792,538	(789,762)	8,588
Total	$ 4,113,657	292,207	792,588	(789,762)	4,408,690
Operating expenses:					
Lease operating	$ 146,990	—	162,376	(163,646)	145,720
Gathering, compression, processing, and transportation	2,257,099	—	41,013	(151,465)	2,146,647
Impairment of oil and gas properties	1,300,444	—	—	—	1,300,444
Impairment of midstream assets	—	—	776,832	(762,050)	14,782
Depletion, depreciation, and amortization	893,161	—	95,526	(73,820)	914,867
General and administrative	160,402	—	118,113	(99,819)	178,696
Other	143,762	549,814	12,093	(11,090)	694,579
Total	4,901,858	549,814	1,205,953	(1,261,890)	5,395,735
Operating income (loss)	$ (788,201)	(257,607)	(413,365)	472,128	(987,045)
Equity in earnings (loss) of unconsolidated affiliates	$ —	—	51,315	(194,531)	(143,216)
Investments in unconsolidated affiliates	$ —	—	709,639	345,538	1,055,177
Segment assets	$ 14,121,523	20,869	6,282,878	(5,227,701)	15,197,569
Capital expenditures for segment assets	$ 1,369,003	—	391,990	(338,838)	1,422,155

(1) Includes the consolidated results of Antero Midstream Partners through March 12, 2019 and results of the Company's equity method investment in Antero Midstream Corporation effective March 13, 2019.

	Exploration and Production	Marketing	Equity Method Investment in Antero Midstream Corporation	Elimination of Intersegment Transactions and Unconsolidated Affiliates	Consolidated Total
Year Ended December 31, 2020					
Sales and revenues:					
Third-party	$ 3,178,330	310,572	—	—	3,488,902
Intersegment	2,797	—	900,719	(900,719)	2,797
Total	$ 3,181,127	310,572	900,719	(900,719)	3,491,699
Operating expenses:					
Lease operating	$ 98,865	—	—	—	98,865
Gathering, compression, processing, and transportation	2,530,838	—	165,386	(165,386)	2,530,838
Impairment of oil and gas properties	223,770	—	—	—	223,770
Impairment of midstream assets	—	—	673,640	(673,640)	—
Depletion, depreciation, and amortization	861,870	—	108,790	(108,790)	861,870
General and administrative	134,482	—	52,213	(52,213)	134,482
Other	125,917	469,404	18,328	(18,328)	595,321
Total	3,975,742	469,404	1,018,357	(1,018,357)	4,445,146
Operating loss	$ (794,615)	(158,832)	(117,638)	117,638	(953,447)
Equity in earnings (loss) of unconsolidated affiliates	$ (62,660)	—	86,430	(86,430)	(62,660)
Investments in unconsolidated affiliates	$ 255,082	—	—	—	255,082
Segment assets	$ 13,150,845	—	5,610,912	(5,610,912)	13,150,845
Capital expenditures for segment assets	$ 874,357	—	196,724	(196,724)	874,357

(19) Subsidiary Guarantors

Each of the Company's wholly owned subsidiaries has fully and unconditionally guaranteed Antero Resources' senior notes. In the event a subsidiary guarantor is sold or disposed of (whether by merger, consolidation, the sale of a sufficient amount of its capital stock so that it no longer qualifies as a "Subsidiary" of Antero (as defined in the indentures governing the notes) or the sale of all or substantially all of its assets (other than by lease)) and whether or not the subsidiary guarantor is the surviving entity in such transaction to a person that is not Antero or a restricted subsidiary of Antero, such subsidiary guarantor will be released from its obligations under its subsidiary guarantee if the sale or other disposition does not violate the covenants set forth in the indentures governing the notes.

In addition, a subsidiary guarantor will be released from its obligations under the indentures and its guarantee, upon the release or discharge of the guarantee of other Indebtedness (as defined in the indentures governing the notes) that resulted in the creation of such guarantee, except a release or discharge by or as a result of payment under such guarantee; if Antero designates such subsidiary as an unrestricted subsidiary and such designation complies with the other applicable provisions of the indentures governing the notes or in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the notes.

The following tables present summarized financial information of Antero and its guarantor subsidiaries. The Company's wholly owned subsidiaries are not restricted from making distributions to the Company.

Balance Sheet

(in thousands)	December 31, 2020 Parent (Antero) and Guarantor Subsidiaries
Accounts receivable, non-guarantor subsidiaries	$ —
Accounts receivable, related parties	—
Other current assets	543,841
Total current assets	543,841
Noncurrent assets	11,783,502
Total assets	$ 12,327,343
Accounts payable, non-guarantor subsidiaries	$ —
Accounts payable, related parties	69,860
Other current liabilities	906,348
Total current liabilities	976,208
Noncurrent liabilities	6,070,388
Total liabilities	$ 7,046,596

Statement of Operations

(in thousands)	Year Ended December 31, 2020 Parent (Antero) and Guarantor Subsidiaries
Revenues	$ 3,458,390
Operating expenses	4,419,323
Loss from operations	(960,933)
Net loss and comprehensive loss including noncontrolling interests	(1,267,897)
Net loss and comprehensive loss attributable to Antero Resources Corporation	$ (1,267,897)

(20) Quarterly Financial Information (Unaudited)

The Company's quarterly consolidated financial information for the years ended December 31, 2019 and 2020 is summarized in the tables below (in thousands, except per share amounts). The Company's quarterly operating results are affected by the volatility of commodity prices and the resulting effect on the Company's production revenues and the fair value of commodity derivatives.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2019				
Total operating revenues	$ 1,037,407	1,299,664	1,118,881	952,738
Total operating expenses	1,071,114	1,199,668	2,104,759	1,020,194
Operating income (loss)	(33,707)	99,996	(985,878)	(67,456)
Gain on deconsolidation of Antero Midstream Partners LP	1,406,042	—	—	—
Net income (loss) and comprehensive income (loss) including noncontrolling interest	1,025,756	42,168	(878,864)	(482,196)
Net income attributable to noncontrolling interest	46,993	—	—	—
Net income (loss) attributable to Antero Resources Corporation	978,763	42,168	(878,864)	(482,196)
Earnings (loss) per common share—basic	$ 3.17	0.14	(2.86)	(1.61)
Earnings (loss) per common share—diluted	$ 3.17	0.14	(2.86)	(1.61)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2020				
Total operating revenues	$ 1,317,105	484,911	380,591	1,309,092
Total operating expenses	1,054,672	1,091,833	1,134,700	1,163,941
Operating income (loss)	262,433	(606,922)	(754,109)	145,151
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(338,810)	(463,068)	(553,846)	95,313
Net income (loss) attributable to noncontrolling interest	—	236	(18,233)	25,483
Net income (loss) attributable to Antero Resources Corporation	(338,810)	(463,304)	(535,613)	69,830
Earnings (loss) per common share—basic	$ (1.19)	(1.73)	(1.99)	0.26
Earnings (loss) per common share—diluted	$ (1.19)	(1.73)	(1.99)	0.24

Operating income is calculated as operating revenues minus operating expenses. During the third and fourth quarters of 2019, operating expenses were impacted by impairments for proved properties, unproved properties and equity method investments that were material to the quarters as presented. See Note 2—Summary of Significant Accounting Policies to the consolidated financial statement for more information.

(21) Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following is supplemental information regarding the Company's consolidated oil and gas producing activities. 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,	
(In thousands)	**2019**	**2020**
Proved properties	$ 11,859,817	12,260,713
Unproved properties	1,368,854	1,175,178
Total oil and gas properties	13,228,671	13,435,891
Accumulated depletion and depreciation	(3,284,330)	(3,818,279)
Net capitalized costs	$ 9,944,341	9,617,612

(b) Costs Incurred in Certain Oil and Gas Activities

(In thousands)	Year Ended December 31, 2018	2019	2020
Acquisition costs:			
Proved property	$ —	—	—
Unproved property	172,387	88,682	45,129
Development costs	1,164,800	1,104,336	823,271
Exploration costs	323,773	149,782	2,993
Total costs incurred	$ 1,660,960	1,342,800	871,393

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

(In thousands)	Year Ended December 31, 2018	2019	2020
Revenues	$ 3,652,894	3,643,873	3,083,905
Operating expenses:			
Production expenses	1,601,985	2,417,509	2,736,478
Exploration expenses	4,958	884	1,083
Depletion and depreciation	832,326	884,350	854,331
Impairment of unproved properties	549,437	1,300,444	223,770
Results of operations before income tax (expense) benefit	664,188	(959,314)	(731,757)
Income tax (expense) benefit	(156,350)	224,511	(176,061)
Results of operations	$ 507,838	(734,803)	(907,818)

(d) Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes the Company's royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the years ended December 31, 2018, 2019 and 2020 were prepared by the Company's reserve engineers and audited by DeGolyer and MacNaughton ("D&M") utilizing data compiled by the Company. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and timing of future development costs. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. All reserves are located in the United States.

Proved reserves are the estimated quantities of oil, condensate, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The Company estimates proved reserves using average prices received for the previous 12 months.

Proved undeveloped reserves include drilling locations that are more than one offset location away from productive wells and are reasonably certain of containing proved reserves and which are scheduled to be drilled within five years under the Company's development plans. The Company's development plans for drilling scheduled over the next five years are subject to many uncertainties and variables, including availability of capital, future commodity prices, net cash provided by operating activities, future drilling and completion costs, and other economic factors.

	Natural Gas (Bcf)	NGLs (MMBbl)	Oil and Condensate (MMBbl)	Equivalents (Bcfe)
Proved reserves:				
December 31, 2017	11,098	989	38	17,261
Revisions	(1,087)	8	(1)	(1,042)
Extensions, discoveries and other additions	2,125	98	12	2,781
Production	(711)	(43)	(3)	(989)
Purchases of reserves	—	—	—	—
December 31, 2018	11,425	1,052	46	18,011
Revisions	(1,735)	25	(11)	(1,648)
Extensions, discoveries and other additions	2,626	169	11	3,705
Production	(822)	(55)	(4)	(1,175)
Purchases of reserves	—	—	—	—
December 31, 2019	11,494	1,191	42	18,893
Revisions	(1,280)	65	(8)	(940)
Extensions, discoveries and other additions	799	48	3	1,105
Production	(875)	(68)	(4)	(1,310)
Sales	(113)	—	—	(113)
Purchases of reserves	—	—	—	—
December 31, 2020 (1)	10,025	1,236	33	17,635

(1) Proved reserves for the noncontrolling interest in Martica as of December 31, 2020 were 254 Bcfe, which consists of 159 Bcf of natural gas, 15 MMBbl of NGLs and 0.5 MMBbl of oil and condensate.

	Natural Gas (Bcf)	NGLs (MMBbl)	Oil and Condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2018	6,669	600	20	10,389
December 31, 2019	7,229	731	21	11,740
December 31, 2020 (1)	6,901	810	19	11,873
Proved undeveloped reserves:				
December 31, 2018	4,756	452	26	7,622
December 31, 2019	4,265	460	21	7,153
December 31, 2020 (2)	3,124	426	14	5,762

(1) Proved developed reserves for the noncontrolling interest in Martica as of December 31, 2020 were 181 Bcfe, which consists of 110 Bcf of natural gas, 11 MMBbl of NGLs and 0.3 MMBbl of oil and condensate.
(2) Proved undeveloped reserves for the noncontrolling interest in Martica as of December 31, 2020 were 73 Bcfe, which consists of 49 Bcf of natural gas, 4 MMBbl of NGLs and 0.2 MMBbl of oil and condensate.

Significant items included in the categories of proved developed and undeveloped reserve changes for the years ended December 31, 2018, 2019 and 2020 in the above table include the following:

2018 Changes in Reserves

- Extensions, discoveries, and other additions of 2,781 Bcfe resulted from delineation and development drilling in the Appalachian Basin.
- Net downward revisions of 1,042 Bcfe include:
  - Downward revisions of 433 Bcfe related to well performance.

- Net downward revisions of 742 Bcfe related to optimization to the Company's five-year development plan. This figure includes upward revisions of 1,722 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 2,464 Bcfe for locations that were not developed within five years of initial booking as proved reserves.

- Upward revisions of 18 Bcfe were due to increases in prices for natural gas, NGLs, and oil.

- Upward revisions of 115 Bcfe are due to an increase in the Company's assumed future ethane recovery.

The Company produced 989 Bcfe during the year ended December 31, 2018.

2019 Changes in Reserves

- Extensions, discoveries, and other additions of 3,705 Bcfe resulted from delineation and development drilling in the Appalachian Basin.

- Net downward revisions of 1,648 Bcfe include:

  - Upward revisions of 63 Bcfe related to well performance.

  - Net downward revisions of 1,705 Bcfe related to optimization to the Company's five-year development plan. This figure includes upward revisions of 595 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 2,300 Bcfe for locations that were not developed within five years of initial booking as proved reserves.

  - Downward revisions of 157 Bcfe were due to increases in prices for natural gas, NGLs, and oil.

  - Upward revisions of 315 Bcfe are due to an increase in the Company's assumed future ethane recovery.

  - Downward revisions of 164 Bcfe are due to the deconsolidation of Antero Midstream Partners. Deconsolidation of Antero Midstream Partners resulted in Antero Resources recording the full fees paid to Antero Midstream Partners for services rendered and no longer including future capital expenditures associated with Antero Midstream Partners' assets in future development costs. Prior to deconsolidation, Antero Resources' consolidated reserves included the elimination of full fees paid by Antero Resources to Antero Midstream Partners and the inclusion of the operating costs and capital incurred by Antero Midstream Partners.

The Company produced 1,175 Bcfe during the year ended December 31, 2019.

2020 Changes in Reserves

- Extensions, discoveries, and other additions of 1,105 Bcfe resulted from delineation and development drilling in the Appalachian Basin.

- Net downward revisions of 940 Bcfe include:

  - Net downward revision of 1,126 Bcfe due to decreases in prices for natural gas, NGLs, and oil.

  - Net downward revision of 922 Bcfe for locations that were not developed within five years of initial booking as proved reserves.

  - Upward revisions of 485 Bcfe are due to an increase in the Company's assumed future ethane recovery.

  - Net upward revision of 132 Bcfe due to schedule optimization primarily driven by previously proved undeveloped properties reclassified from non-proved to proved undeveloped.

  - Net upward performance revisions of 491 Bcfe.

- Sales of reserves of 113 Bcfe related to the VPP.

The Company produced 1,310 Bcfe during the year ended December 31, 2020.

(e) Standardized Measure of Discounted Future Net Cash Flow

The following table sets forth the standardized measure of the discounted future net cash flows attributable to the Company's proved reserves. Future cash inflows were computed by applying historical 12 month unweighted first day of the month average prices. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pretax net cash flows relating to the Company's proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of available NOL carryforwards and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

	Year Ended December 31,		
(in millions)	**2018**	**2019**	**2020**
Future cash inflows	$ 64,199	54,228	37,845
Future production costs	(30,007)	(36,524)	(32,202)
Future development costs	(3,453)	(2,772)	(1,685)
Future net cash flows before income tax	30,739	14,932	3,958
Future income tax expense [(1)]	(5,505)	(1,639)	—
Future net cash flows	25,234	13,293	3,958
10% annual discount for estimated timing of cash flows	(14,756)	(7,824)	(2,748)
Standardized measure of discounted future net cash flows [(2)]	$ 10,478	5,469	1,210

(1) Based on the 12-month average of the first-day-of-the-month prices used in the computation of PV-10 as of December 31, 2020, the future taxable net income generated over the life of the Company's proved reserves is expected to be less than its NOL carryforward deductions and therefore, under the standardized measure, there is no deduction for federal or state income taxes.

(2) The standardized measure of discounted future net cash flows for the noncontrolling interest in Martica was $359 million for the year ended December 31, 2020.

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

	Year Ended December 31,		
	2018	**2019**	**2020**
12-month weighted average price	$ 3.56	2.87	2.15

(f) Changes in Standardized Measure of Discounted Future Net Cash Flow

	Year Ended December 31,		
(in millions)	**2018**	**2019**	**2020**
Sales of oil and gas, net of productions costs	$ (2,051)	(1,116)	(347)
Net changes in prices and production costs [1]	707	(6,729)	(5,455)
Development costs incurred during the period	755	758	704
Net changes in future development costs [2]	37	(92)	249
Extensions, discoveries and other additions	1,925	782	31
Acquisitions	—	—	—
Divestitures	—	—	(174)
Revisions of previous quantity estimates	(53)	(1,011)	(379)
Accretion of discount	1,018	1,259	607
Net change in income taxes	(563)	1,513	598
Changes in timing and other	76	(373)	(93)
Net increase (decrease)	1,851	(5,009)	(4,259)
Beginning of year	8,627	10,478	5,469
End of year [3]	$ 10,478	5,469	1,210

(1) Includes $3.3 billion in increased production costs due to the deconsolidation of Antero Midstream Partners for the year ended December 31, 2019.
(2) Includes $185 million in increased future development costs due to the deconsolidation of Antero Midstream Partners for the year ended December 31, 2019.
(3) The standardized measure of discounted future net cash flows for the noncontrolling interest in Martica was $359 million for the year ended December 31, 2020.

CORPORATE INFORMATION

BOARD OF DIRECTORS

PAUL M. RADY
Chairman and CEO

GLEN C. WARREN, JR
President, CFO, and Director

BENJAMIN A. HARDESTY
Lead Director

ROBERT J. CLARK
Director

W. HOWARD KEENAN, JR.
Director

PAUL J. KORUS
Director

JACQUELINE C. MUTSCHLER
Director

VICKY SUTIL
Director

TOM B. TYREE
Director

SENIOR MANAGEMENT

PAUL M. RADY
Chairman and CEO

GLEN C. WARREN, JR.
President, CFO, and Director

MICHAEL N. KENNEDY
SVP – Finance

ALVYN A. SCHOPP
Chief Administrative Officer and Regional SVP

J.KEVIN ELLIS
Regional VP

STEVEN M. WOODWARD
SVP – Business Development

W. PATRICK ASH
SVP – Reserves, Planning and Midstream

TROY R. ROACH
VP – Health, Safety, and Environment

DIANA O. HOFF
SVP – Operations

YVETTE K. SCHULTZ
General Counsel and VP – Legal

SHERI L. PEARCE
VP – Accounting and Chief Accounting Officer

BRENDAN E. KRUEGER
VP – Finance and Treasurer

JOHN GIANNAULA
VP – Human Resources and Administration

AARON S. G. MERRICK
VP – Information Technology

ROBERT H. KRCEK
VP – Midstream Operations

TIMOTHY J.C. RADY
VP – Land

MARIA WOOD HENRY
VP – Geology

JUSTIN B. FOWLER
VP – Gas Marketing and Transportation

DAVID A. CANNELONGO
VP – Liquids Marketing and Transportation

MICHAEL W. SMITH
VP – Logistics and Cost Management

JON S. McEVERS
VP – Completions

ROBERT S. ODENTHAL
VP – Drilling

MATTHEW L. THOMAS
VP – Risk Management

INVESTOR RELATIONS

ANTERO RESOURCES CORPORATION
1615 Wynkoop Street
Denver, Colorado 80202
(303) 357-7310 extension 6782
www.anteroresources.com

TRANSFER AGENT AND REGISTRAR

AMERICAN STOCK TRANSFER AND TRUST COMPANY, LLC
6201 15th Avenue
Brooklyn, New York 11219
(800) 937-5449

RESERVE AUDITOR

DEGOLYER AND MACNAUGHTON
Dallas, Texas

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP Denver, Colorado

SHAREHOLDER INFORMATION

Our common shares are publicly traded on the NYSE under the symbol "AR"

CORPORATE HEADQUARTERS

ANTERO RESOURCES CORPORATION
1615 Wynkoop Street
Denver, Colorado 80202

FORWARD-LOOKING STATEMENTS

The 2020 Annual Report includes "forward-looking statements." Such forward-looking statements are subject to a number of risks and uncertainties, many of which are not under Antero Resources Corporation's ("Antero") control. All statements, except for statements of historical fact, made herein regarding activities, events or developments Antero expects, believes or anticipates will or may occur in the future, such as those regarding expected results, future commodity prices, future production targets, completion of natural gas or NGL transportation projects, future earnings, future capital spending plans, improved and/or increasing capital efficiency, estimated realized natural gas, NGL and oil prices, access to multiple gas markets, expected drilling and development plans, projected well costs and cost savings initiatives, future financial position, future technical improvements, and future marketing opportunities, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although Antero believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements. Antero cautions you that these forward-looking statements are subject to all of the risks and uncertainties incident to Antero's business, most of which are difficult to predict and many of which are beyond Antero's control. These risks include, but are not limited to, commodity price volatility, inflation, availability of drilling, completion and production equipment and services, environmental risks, drilling and completion and other operating risks, marketing and transportation risks, regulatory changes, 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 world health events, including the COVID-19 pandemic[, potential shut-ins of production due to lack of downstream demand or storage capacity] and the other risks described under the heading "Item 1A. Risk Factors" in Antero's Annual Report on Form 10-K for the year ended December 31, 2020. Any forward-looking statement speaks only as of the date on which such statement is made, and Antero does not undertake any obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

For a definition of free cash flow and a reconciliation to its most comparable measure calculated in accordance with GAAP for the year ended December 31, 2020, please see "Item 6. Selected Financial Data" in our Annual Report on Form 10-K for the year ended December 31, 2020.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