ANTERO RESOURCES | 2019 ANNUAL REPORT

Antero
Resources

ANTERO RESOURCES BUSINESS STRATEGY

BUILD SCALE WITH LIQUIDS DIVERSIFICATION

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

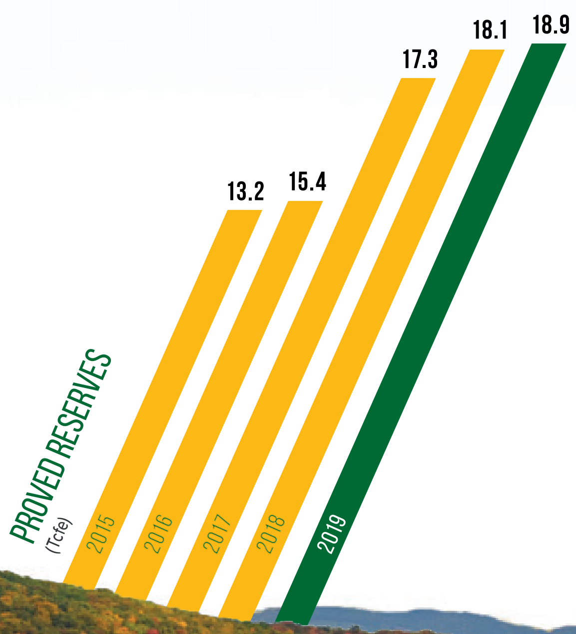
LEADING SUSTAINABILITY AND ESG METRICS

Cover photo: Pyle Run Pad in Tyler County, WV

DEAR FELLOW SHAREHOLDERS,

Antero Resources (NYSE: AR) delivered many notable accomplishments during 2019, further strengthening the Company's position as a premier Appalachian Basin producer. Driven by the successful execution of our development plan, we averaged a record 3.2 Bcfe/d of net production during the year while growing average production by 19% over the previous year. Our liquids volumes averaged 161,000 Bbl/d in 2019, ranking Antero as the second largest natural gas liquids (NGL) producer in the United States. Antero Resources also exited 2019 as the fifth largest natural gas producer in the U.S., averaging 2.3 Bcf/d of dry gas production during the year. We grew our proved reserves by 5% to 18.9 Tcfe, including a 13% increase in proved developed reserves. All of these achievements were reached while executing on a cost reduction and efficiency initiative that resulted in well costs exiting the year at $795 per lateral foot, 18% below the initial 2019 budget. This operational momentum positions Antero Resources to generate significant value for our shareholders on a sustained basis over the coming years.

The Antero Family had a transformational year in 2019, closing the acquisition of Antero Midstream Partners by Antero Midstream GP and converting the partnership into a corporation. The tax-efficient transaction simplified the Antero Family structure, eliminated the incentive distribution rights, and significantly enhanced shareholder rights and corporate governance. Following the closing of the midstream simplification transaction, Antero Resources no longer consolidates Antero Midstream (NYSE: AM) in its financial statements, significantly improving our transparency and disclosure.



EFFICIENT AND VALUE-FOCUSED SHALE DEVELOPMENT

Antero Resources continued to be one of the most active operators in Appalachia in 2019, running an average of four drilling rigs and turning 131 horizontal wells to sales during the year. Our core contiguous acreage position allows for long lateral drilling and highly efficient operations, both upstream and midstream. These efficiencies led to new operational records in 2019. The 131 well completions had an average lateral length of 11,062 feet, a 10% increase from the prior year. We completed an average of 6.3 stages per day during the fourth quarter of 2019, a 21% increase from the average in 2018. Going forward, we have a core inventory of more than 2,700 drilling locations that includes an extensive mix of both liquids-rich and dry gas locations. This attractive mix allows us to focus our development plan on the highest return acreage.

RELENTLESS FOCUS ON COST REDUCTION

Throughout 2019 we maintained an intense focus on reducing our corporate cost structure. Through a combination of lower well costs, reduced lease operating expense, gathering, processing and transportation expense, and general and administrative costs, we are targeting a $620 million reduction in our capital and operating cost structure for 2020.

Our liquids volumes averaged 161,000 Bbl/d in 2019, making Antero the second largest natural gas liquids (NGL) producer in the United States.

18.9 Tcfe
Net Proved Reserves

541,000
Net Acres

2,700 +
Undeveloped Drilling Locations

$0.33 Mcfe
Marcellus F&D Cost

$6.1 Billion
SEC PV-10 Proved Reserve Value

29%
AM Ownership

39%
Liquids Revenue Contribution

151,000
Natural Gas Liquids Production

In 2020 we will remain steadfast in continuing to reduce our overall cost structure, with a goal of being a peer leader in returns regardless of the commodity cycle. This persistent effort to reduce costs has already delivered benefits as highlighted by our latest 2020 well cost target of $715 per foot, 25% below the year-ago level.

READY FOR THE FUTURE

Looking ahead, our development plan targets capital spending within cash flow while continuing to deliver modest growth. In 2020, we are expecting gas-equivalent production growth of just below 10% despite a drilling and completion capital budget that is 39% below 2019.

As one of the largest NGL producers in the United States, Antero is well positioned to capitalize on improving liquids pricing. In early 2019, we gained significant access to global NGL markets and pricing through our commitment on the Mariner East 2 Pipeline. This pipeline transports NGL products from our producing areas in West Virginia and Ohio to the Marcus Hook terminal and dock on the Delaware River near Philadelphia for international shipping. We expect to sell at least 50% of our NGLs into the global markets in 2020, diversifying our liquids pricing exposure and providing another link to premium price realizations.

We also continue to deliver pre-hedge natural gas realizations at a premium to benchmark pricing due to our firm transportation portfolio. Our 2.1 Bcf/d of transportation capacity to the Gulf Coast enables Antero to be one of the largest suppliers to the growing LNG export business in the U.S., which allows us to receive premium natural gas price realizations.

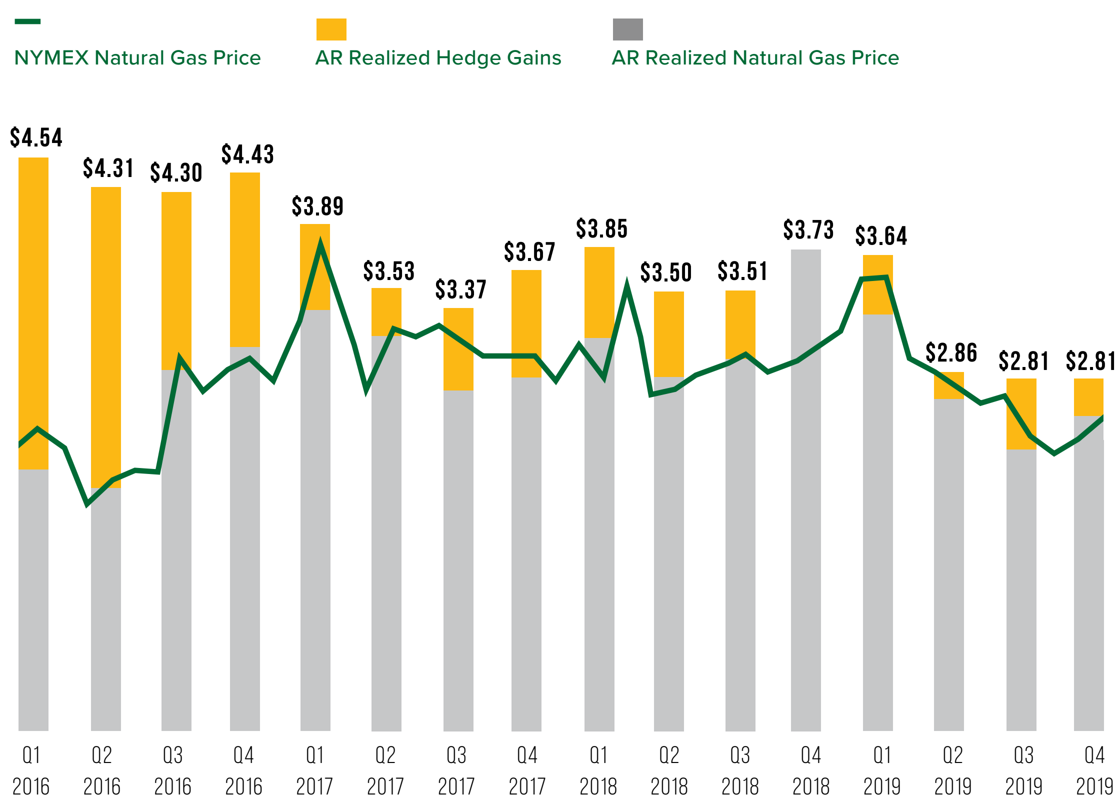
Antero is one of the largest suppliers to the growing LNG export business in the U.S., which directly contributes to our ability to receive premium natural gas price realizations.

To ensure continued favorable price realizations, we have built an industry-leading natural gas hedge position at prices well above current futures market prices.

The combination of our large scale, diversified product pricing exposure and increasing capital efficiency provides Antero 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

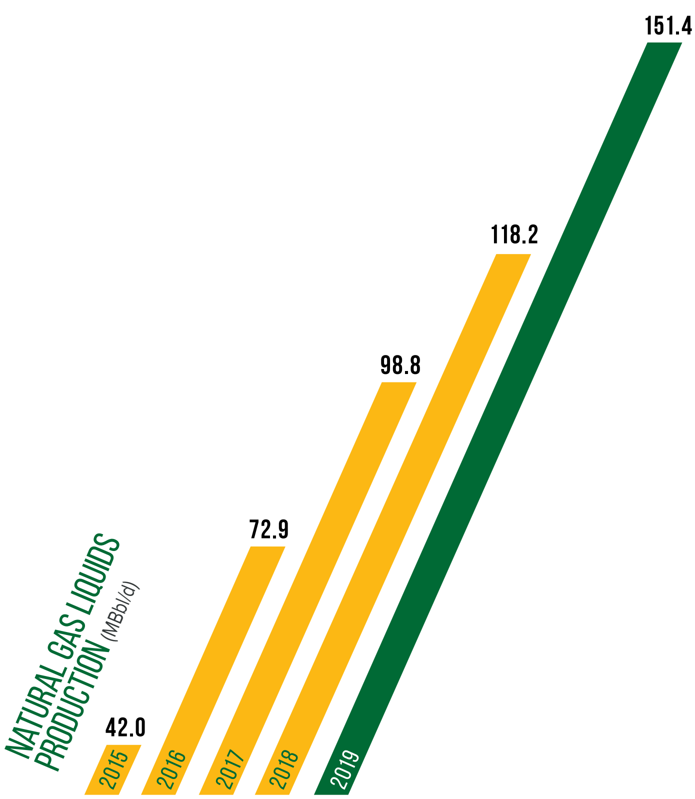
Following the simplification of the midstream structure, we own 29% of Antero Midstream Corporation's shares. Antero Midstream is an integrated midstream service provider whose primary role is to support the growth of Antero Resources in Appalachia. Through its gathering and compression business, Antero 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 and flowback and produced water services for Antero Resources. At year-end 2019, through the processing and fractionation joint venture with MPLX (NYSE: MPLX), the capacity at the Sherwood gas processing complex was increased to 2.8 Bcf/d, including 60,000 Bbl/d of de-ethanization. In 2020, we anticipate our first gas processing plant at the new and nearby Smithburg facility will be placed in service. The joint venture has been expanded to include all six of the planned processing plants for the Smithburg processing complex. Additionally, the joint venture has total fractionation capacity of 40,000 Bbl/d at the Hopedale fractionation complex. These assets will continue to contribute to growth and profitability in the coming years. Overall, 2019 was another year of continued growth and value chain buildout for Antero Midstream.



CONSISTENTLY RECEIVING ABOVE BENCHMARK NYMEX NATURAL GAS PRICING

HEALTH, SAFETY AND THE ENVIRONMENT

Antero's commitment to health, safety and the environment is a core value of our organization. We have a culture dedicated to safety and environmental stewardship. This reduces risk, enhances productivity, and elevates our reputation in the communities in which we operate. We invest heavily in safety training and coaching of our employees and contractors. We promote risk assessment and encourage visible safety leadership, and we sponsor emergency preparedness programs. On the environmental front, Antero Resources is committed to methane leak reduction opportunities through our membership in the EPA Natural Gas Star Program. The program implements methane loss reduction projects and reports the reductions of methane emissions per unit of production to the EPA every year. We also report our yearly Greenhouse Gas emissions as a rate per production and our methane leak rate. We are proud to state that Antero's Greenhouse Gas emissions intensity dropped once again in 2019 from 2018 to just 2.3 CO2E tons per Mboe despite an increase in production, placing Antero as a peer leader in the oil & gas industry. Further, Antero's methane leak loss rate was just 0.05% in 2019, which is well ahead of the gas production and gathering segment goal of 0.28% and the ONE Future target of below 1% by 2025. Finally, highlighting our commitment to Environmental, Safety and Governance leadership (ESG), both Antero Resources and Antero Midstream have established ESG committees on their respective Boards of Directors. Thanks to continuous improvement in our safety and environmental performance, Antero is viewed as a safe and environmentally responsible operator.

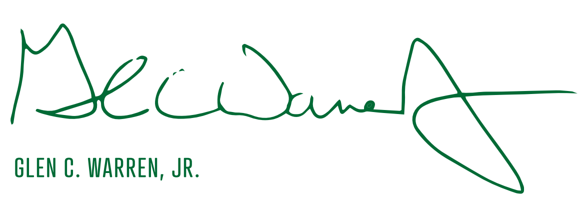


THE PEOPLE OF ANTERO

We want to express appreciation for the hard work and dedication of our talented employees. The people of Antero Resources generate value creation and momentum year after year in what has been a challenging market environment. Their skills and expertise in assembling and executing world-class projects represent the true strength and competitive advantage of Antero Resources. We are also grateful for 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 2020, and for many years to come.

PAUL M. RADY

Chairman and CEO



GLEN C. WARREN, JR.

President and CFO


2019
FORM 10K
Antero
Resources

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, 2019

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

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $1.5 billion based on the $5.53 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 286,677,115 shares of common stock outstanding as of February 7, 2020.

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. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. 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 belief, 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;
- timing and amount of future production of natural gas, NGLs, and oil;
- our hedging strategy and results;
- our ability to successfully execute our share repurchase program, debt repurchase program and/or our asset sale program;
- 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 and treatment 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, 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.

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:

"*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.

"*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 used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*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 one barrel of oil, condensate or NGLs converted to six cubic feet 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.

"*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.

"*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.

"*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 oil, natural gas and natural gas liquids 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 exploration, development, 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. As of December 31, 2019, we held approximately 541,000 net acres of oil and gas properties located in the Appalachian Basin in West Virginia and Ohio. Our corporate headquarters are in Denver, Colorado.

Ownership in Antero Midstream

In 2014, 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, par value $0.01 per share, in exchange for our 98,870,335 common units representing limited partner interests in Antero Midstream Partners owned immediately prior to the Transactions.

Prior to the Transactions, our ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and we consolidated Antero Midstream Partners’ financial position and results of operations into our consolidated financial statements. The Transactions resulted in us owning approximately 31% of Antero Midstream’s common stock. As a result, 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. Because Antero Midstream Partners does not meet the requirements of a discontinued operation, Antero Midstream Partners’ results of operations continue to be included in our consolidated statement of operations and comprehensive income (loss) through March 12, 2019. Please see Note 3 to the consolidated financial statements for more information on the Transactions.

On December 16, 2019, we sold 19,377,592 shares of Antero Midstream’s common stock to Antero Midstream at a price of $5.1606 per share, which shares were thereafter cancelled by Antero Midstream, resulting in aggregate proceeds to us of $100 million. This reduced our interest in Antero Midstream to approximately 28.7% at December 31, 2019.

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.

	At December 31, 2019						Three months ended December 31, 2019
	Proved Reserves (Bcfe)[1]	PV-10 (in millions)[2]		Net proved developed wells[3]	Total net acres	Gross potential drilling locations[4]	Average net daily production (MMcfe/d)
Appalachian Basin:							
Marcellus Shale	17,350	$	5,500	923	450,633	2,211	2,832
Ohio Utica Shale	1,543	$	567	207	90,814	174	353
Total	18,893	$	6,067	1,130	541,447	2,385	3,185

(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, 2019, which were $2.41 per MMBtu for natural gas based on a $2.63 per MMBtu NYMEX reference price, $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 per Bbl WTI reference price.

(2) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 of $6.1 billion to the Standardized measure of $5.5 billion, please see "—Our Properties and Operations—Estimated Proved Reserves."

(3) Does not include certain vertical wells with no proved reserves booked that were primarily acquired in conjunction with leasehold acreage acquisitions.

(4) Gross potential drilling locations are comprised of 328 locations classified as proved undeveloped, 1,958 locations classified as probable and 99 locations classified as 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.

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 profitably grow our reserves and production, primarily on our existing multi-year project inventory.

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 Marcellus Shale and Utica Shale of the Appalachian Basin. We have 2,385 potential horizontal well locations on our existing leasehold acreage within our proved, probable, and possible reserve categories.

We have secured sufficient long-term firm takeaway capacity on major pipelines in each of our core operating areas to accommodate our current development plans.

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) the gathering and processing of natural gas through our equity method investment in Antero Midstream Corporation. 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 to the consolidated financial statements for further discussion on our industry segment operations.

2019 and Recent Developments and Highlights

Reserves, Production, and Financial Results

As of December 31, 2019, our estimated proved reserves were 18.9 Tcfe, consisting of 11.5 Tcf of natural gas, 652 MMBbl of ethane, 540 MMBbl of C3+ NGLs, and 42 MMBbl of oil. As of December 31, 2019, 61% of our estimated proved reserves by volume were natural gas, 38% were NGLs, and 1% was oil. Proved developed reserves were 11.7 Tcfe, or 62% of total proved reserves.

For the year ended December 31, 2019, our net production totaled 1,175 Bcfe, or 3,220 MMcfe per day, a 19% increase compared to 989 Bcfe, or 2,709 MMcfe per day, for the year ended December 31, 2018. Production growth resulted from an increase in the number of producing wells as a result of our drilling and completion activity. Our average price received for production, before the effects of gains on settled commodity derivatives, for the year ended December 31, 2019 was $3.10 per Mcfe compared to $3.69 per Mcfe for the year ended December 31, 2018. Our average realized price after the effects of gains on settled commodity derivatives was $3.38 per Mcfe for the year ended December 31, 2019 as compared to $3.94 per Mcfe for the year ended December 31, 2018.

For the year ended December 31, 2019, we generated consolidated cash flows from operations of $1.1 billion, a consolidated net loss of $340 million and Adjusted EBITDAX of $1.2 billion. This compares to cash flows from operations of $2.1 billion, a consolidated net loss of $398 million, Adjusted EBITDAX of $1.7 billion for the year ended December 31, 2018. See "Item 6. Selected Financial Data" for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

Consolidated net loss for 2019 included (i) commodity derivative fair value gains of $464 million, comprised of gains on settled derivatives of $325 million and a non-cash gain of $139 million on changes in the fair value of commodity derivatives, (ii) a non-cash charge of $24 million for equity-based compensation, (iii) a non-cash charge of $1.3 billion for impairments of oil and gas properties, (iv) a non-cash charge of $468 million for an impairment of equity investments and (v) a non-cash deferred tax benefit of $79 million.

2019 Capital Spending and 2020 Capital Budget

For the year ended December 31, 2019, our total consolidated capital expenditures were approximately $1.4 billion, including drilling and completion expenditures of $1.3 billion, leasehold additions of $89 million, gathering and compression expenditures of $48 million, water handling and treatment expenditures of $24 million, and other capital expenditures of $7 million. Our capital budget for 2020 is $1.2 billion. Our budget includes: $1.15 billion for drilling and completion and $50 million for leasehold expenditures. We do not budget for acquisitions. During 2020, we plan to operate an average of four drilling rigs and three to four completion crews and we plan to complete 120 to 130 horizontal wells in the Marcellus and Utica Shales in 2020. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Furthermore, in December 2019, we announced an asset sale program pursuant to which we expect to execute between $750 million and $1.0 billion asset monetization opportunities through 2020, which can include dispositions of lease acreage, minerals, producing properties or our shares of Antero Midstream common stock, or hedge restructuring. We expect to use the proceeds from this program to reduce indebtedness. We initiated this program by selling $100 million of our shares of Antero Midstream common stock in December 2019 to Antero Midstream.

Hedge Position

At December 31, 2019, we had fixed price swap contracts in place for January 1, 2020 through December 31, 2023 for 1.7 Tcf of our projected natural gas production at a weighted average index price of $2.84 per MMBtu. These hedging contracts include contracts for the year ending December 31, 2020 of 815 Bcf of natural gas at a weighted average price of $2.87 per MMBtu. We also have fixed price swaps for NGLs and Oil for approximately 15 MMBbls for the year ending December 31, 2020 at weighted average index prices of $0.50 to $0.81 per gallon and $55.63 per Bbl, respectively. Additionally, we have basis swaps in place for January 1, 2020 through December 31, 2024 for 95 Bcf of our projected natural gas production with pricing differentials ranging from $0.35 to $0.53 per MMBtu. See Note 11 to the consolidated financial statements for more information on our current hedge position.

To the extent we have hedged the price of a portion of our estimated future production through 2024, we believe this hedge position provides some certainty to cash flows supporting our future operations and capital spending plans. As of December 31, 2019, the estimated fair value of our commodity net derivative contracts was approximately $746 million.

Credit Facility

At December 31, 2019, the borrowing base under our senior secured revolving credit facility (the "Credit Facility") was $4.5 billion and lender commitments were $2.64 billion. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the earliest stated redemption date of any series of Antero's senior notes then outstanding. The borrowing base under the Credit Facility is redetermined annually and is based on the estimated future cash flows from our proved oil and gas reserves and our commodity derivative positions. The next redetermination is scheduled to occur in April 2020. At 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 revolving credit facility. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Senior Secured Revolving Credit Facility" for a description of the Credit Facility.

Debt Repurchase Program

During the fourth quarter of 2019, we repurchased $225 million principal amount of debt at a 17% weighted average discount, including a portion of our 5.375% senior notes due November 1, 2021 (the “2021 notes”) and our 5.125% senior notes due December 1, 2022 (the “2022 notes”). As of December 31, 2019, we have $952.5 million in aggregate principal amount outstanding of our 2021 notes and $923.0 million in aggregate principal amount outstanding of our 2022 notes. See Note 7 to the consolidated financial statements for more information on long-term debt.

Share Repurchase Program

In October 2018, our Board of Directors authorized a $600 million share repurchase program through March 31, 2020. During the year ended December 31, 2019, we repurchased 13.4 million shares of our common stock (approximately 4% of total shares outstanding at commencement of the program) at a total cost of approximately $39 million. See “Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities—Issuer Purchases of Equity Securities.”

Our Properties and Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared in accordance with the rules and regulations of the Securities and Exchange Commission (the “SEC”).

Reserves Presentation

The following table summarizes our estimated proved reserves, related Standardized measure, and PV-10 at December 31, 2017, 2018 and 2019. The decrease in pre-tax estimated proved reserves PV-10 value as compared to 2018, was due primarily to lower SEC pricing and the deconsolidation of Antero Midstream Partners from Antero Resources’ financial statements. The deconsolidation resulted in Antero Resources recording the full fees paid to Antero Midstream Partners for services rendered and no longer recording the capital expenditures associated with Antero Midstream Partners. 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 associated with Antero Midstream Partners.

Our estimated proved reserves are based on evaluations prepared by our internal reserve engineers, which 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 at December 31, 2019 is filed as Exhibit 99.1 to this Annual Report on Form 10-K. Within D&M, the technical person primarily responsible for reviewing our reserves estimates was Gregory K. Graves, P.E. Mr. Graves is a Registered Professional Engineer in the State of Texas (License No. 70734), is a member of both the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers, and has in excess of 34 years of experience in oil and gas reservoir studies and reserves evaluations. Mr. Graves graduated from the University of Texas at Austin in 1984 with a Bachelor of Science degree in Petroleum Engineering. Reserves at December 31, 2017, 2018 and 2019 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.

	At December 31,		
	2017	**2018**	**2019**
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	5,587	6,669	7,229
Ethane (MMBbl)	268	341	428
C3+ NGLs (MMBbl)	199	259	302
Oil (MMBbl)	16	20	21
Total equivalent proved developed reserves (Bcfe)	8,488	10,389	11,740
Proved undeveloped reserves:			
Natural gas (Bcf)	5,511	4,756	4,265
Ethane (MMBbl)	260	213	224
C3+ NGLs (MMBbl)	262	238	237
Oil (MMBbl)	22	26	20
Total equivalent proved undeveloped reserves (Bcfe)	8,773	7,622	7,153
Proved developed producing (Bcfe)	7,996	9,841	11,267
Proved developed non-producing (Bcfe)	492	548	473
Percent developed	49 %	58 %	62 %
Total estimated proved reserves (Bcfe)	17,261	18,011	18,893
PV-10 (in millions)(1)	$ 10,175	$ 12,589	$ 6,067
Standardized measure (in millions)(1)	$ 8,627	$ 10,478	$ 5,469

(1) PV-10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. 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 to the consolidated financial statements for more information about the calculation of Standardized measure.

The following sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity derivatives), the present value of those net cash flows before income tax (PV-10), the present value of those net cash flows after income tax (Standardized measure) and the prices used in projecting future net cash flows at December 31, 2017, 2018 and 2019:

	At December 31,		
(In millions)	**2017(1)**	**2018(2)**	**2019(3)**
Future net cash flows	$ 26,137	$ 30,739	$ 14,932
Present value of future net cash flows:			
Before income tax (PV-10)	$ 10,175	$ 12,589	$ 6,067
Income taxes	$ (1,548)	$ (2,111)	$ (598)
After income tax (Standardized measure)	$ 8,627	$ 10,478	$ 5,469

(1) 12 month average prices used at December 31, 2017 were $2.91 per MMBtu for natural gas, $9.95 per Bbl for ethane, $32.37 per Bbl for C3+ NGLs, and $45.35 per Bbl for oil for the Appalachian Basin based on a $51.03 WTI reference price.

(2) 12 month average prices used at December 31, 2018 were $2.93 per MMBtu for natural gas, $12.26 per Bbl for ethane, $39.29 per Bbl for C3+ NGLs and $56.62 per Bbl for oil for the Appalachian Basin based on a $65.66 WTI reference price.

(3) 12 month average prices used at 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.

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Prices for 2017, 2018 and 2019 were based on 12-month unweighted average of the first-day-of-the-month pricing, without escalation. Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information, and different reservoir engineers often arrive at different estimates for the same properties.

Changes in Proved Reserves During 2019

The following table summarizes the changes in our estimated proved reserves during 2019 (in Bcfe):

Proved reserves, December 31, 2018	18,011
Extensions, discoveries, and other additions	3,705
Performance revisions	63
Revisions to five-year development plan	(1,705)
Price revisions	(157)
Deconsolidation of Antero Midstream Partners	(164)
Revisions to ethane recovery	315
Production	(1,175)
Proved reserves, December 31, 2019	18,893

Extensions, discoveries, and other additions of 3,705 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales. Included in the extensions are 1,202 Bcfe of volumes associated with a third party acreage trade. Upward revisions of 63 Bcfe related to well performance. Net downward revisions of 1,705 Bcfe related to optimization of our five-year development plan. This figure includes upward revisions of 595 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2018 to proved undeveloped at December 31, 2019 due to their addition to our 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 decreases in prices for natural gas, NGLs, and oil. Downward revisions of 164 Bcfe were due to an increase in fee structure resulting from 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. Upward revisions of 315 Bcfe were due to an increase in our assumed future ethane recovery. Our estimated proved reserves as of December 31, 2019 totaled approximately 18,893 Bcfe, an increase of 5% 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 2019 (in Bcfe):

Proved undeveloped reserves, December 31, 2018	7,622
Extension, discoveries, and other additions	3,433
Performance revisions	141
Revisions to five-year development plan	(1,705)
Price revisions	(30)
Deconsolidation of Antero Midstream Partners	(42)
Reclassifications to proved developed reserves	(2,201)
Revisions to ethane recovery	(65)
Proved undeveloped reserves, December 31, 2019	7,153

Extensions, discoveries, and other additions during 2019 of 3,433 Bcfe of proved undeveloped reserves resulted from delineation and developmental drilling in the Marcellus and Utica Shales. Included in the extensions are 1,173 Bcfe of volumes associated with a third party acreage trade. Upward revisions of 141 Bcfe related to well performance. Net downward revisions of 1,705 Bcfe related to optimization of our five-year development plan. This figure includes upward revisions of 595 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2018 to proved undeveloped at December 31, 2019 due to their addition to our 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 30 Bcfe were due to decreases in prices for natural gas, NGLs, and oil. Downward revisions of 42 Bcfe were due to an increase in fee structure resulting from 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 Antero Resources 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.

During the year ended December 31, 2019, we converted approximately 2,201 Bcfe, or 29%, of our proved undeveloped reserves to proved developed reserves at a total capital cost of approximately $788 million. We spent an additional $316 million on development costs related primarily to drilled and uncompleted wells and properties in the proved undeveloped classification at December 31, 2018, resulting in total development spending of $1.1 billion, as disclosed in Note 21 to the consolidated financial statements included elsewhere in this report. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2019 are approximately $2.6 billion, or $0.37 per Mcfe, over the next five years. Based on strip pricing as of December 31, 2019, we believe that cash flows from operations 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 growth 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. As our well economics have changed, we have reallocated five-year capital to areas with expected highest rates of return and optimal lateral lengths. This resulted in the reclassification of 2,300 Bcfe of reserves from proved undeveloped to probable during the year ended December 31, 2019 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.

At December 31, 2019, an estimated 8,500 of our net leasehold acres, containing 227 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 $21 million to renew the 8,500 acres based upon current leasing authorizations and option to extend payments. Proved undeveloped reserves of 687 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 103 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 reserve estimates as of December 31, 2017, 2018 and 2019 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. Our internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. 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 our independent reserve engineers 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 the independent reserve engineers 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 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.

Proved reserves are reserves that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps and available downhole and production data, micro-seismic data, and well-test data. Probable reserves are reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves that may potentially be recoverable through additional drilling or recovery techniques are, by nature, more uncertain than estimates of proved reserves and, accordingly, are subject to substantially greater risk of realization. Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes, and other factors.

Methodology Used to Apply Reserve Definitions

In the Marcellus Shale, our estimated reserves are based on information from our large, operated proved developed producing reserve base, as well as information from other operators in the area, which can be used to confirm or supplement our internal estimates. Typically, proved undeveloped properties are booked based on applying the estimated lateral length to the average wellhead Bcf per 1,000 feet from our proved developed producing wells, then converting to a processed volume where applicable.

We may attribute up to 11 proved undeveloped locations based on one proved developed producing well where analysis of geologic and engineering data can be estimated with reasonable certainty to be commercially recoverable. However, the ratio of proved undeveloped locations generated will be lower when multiple proved developed wells are drilled on a single pad. In addition, we have applied the concept of a statistically proven area to certain areas of our Marcellus Shale acreage whereby undeveloped properties are booked as proved reserves so long as well count is sufficient for statistical analysis and certain land, geologic, engineering and commercial criteria are met.

Although our operating history in the Utica Shale is more limited than our Marcellus Shale operations, we expect to be able to apply a similar methodology once the well count is sufficient for statistical analysis. The primary differences between the two areas are that (i) we have not established a statistically proven area in the Utica Shale and (ii) each proved developed producing well in the Utica Shale only generates four direct offset well locations due to less relative maturity of the play.

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, 2019. 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, Revenues, and Price History

Because natural gas, NGLs, and oil are commodities, the prices that we receive for our production are largely a function of market supply and demand. While demand for natural gas in the United States has increased materially since 2000, natural gas and NGLs supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have been used to find and recover large amounts of oil and gas from various shale formations throughout the United States. Demand 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."

Operations Data – 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, 2017, 2018 and 2019. 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,		
	2017	2018	2019
Production data:			
Natural gas (Bcf)	591	710	822
C2 Ethane (MBbl)	10,539	14,221	15,861
C3+ NGLs (MBbl)	25,507	28,913	39,445
Oil (MBbl)	2,451	3,265	3,632
Combined (Bcfe)	822	989	1,175
Daily combined production (MMcfe/d)	2,253	2,709	3,220
Average sales prices before effects of derivative settlements:			
Natural gas (per Mcf)	$ 2.99	$ 3.22	$ 2.74
C2 Ethane (per Bbl)	$ 8.83	$ 12.14	$ 7.85
C3+ NGLs (per Bbl)	$ 30.48	$ 34.76	$ 27.75
Oil (per Bbl)	$ 44.14	$ 57.34	$ 48.88
Combined average sales prices before effects of derivative settlements (per Mcfe) (1)	$ 3.34	$ 3.69	$ 3.10
Combined average sales prices after effects of derivative settlements (per Mcfe) (1)	$ 3.60	$ 3.94	$ 3.38
Average Costs (per Mcfe) (2)**:**			
Lease operating	$ 0.11	$ 0.14	$ 0.13
Gathering, compression, processing, and transportation	$ 1.75	$ 1.81	$ 1.92
Production and ad valorem taxes	$ 0.11	$ 0.12	$ 0.11
Marketing, net	$ 0.13	$ 0.23	$ 0.22
Depletion, depreciation, amortization, and accretion	$ 0.86	$ 0.85	$ 0.76
General and administrative (excluding equity-based compensation)	$ 0.14	$ 0.13	$ 0.12

(1) Average sales prices shown in the table reflect both the before and after effects of our settled derivatives. Our calculation of such after effects includes gains on settlements of derivatives excluding proceeds from the derivative monetizations in 2017 and 2018. Our hedges 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.

(2) 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.

Productive Wells

As of December 31, 2019, we held interests in a total of 1,238 gross (1,148.2 net) producing wells on our Marcellus Shale acreage, including the following:

- 915 gross (904.4 net) horizontal wells, averaging a 99% working interest, operated by us.
- 64 gross (5.6 net) horizontal wells operated by other producers.
- 259 gross (238.2 net) shallow vertical wells.

As of December 31, 2019, we held interests in a total of 244 gross (206.3 net) producing wells on our Ohio Utica Shale acreage, including the following:

- 222 gross (206.2 net) horizontal wells, averaging a 93% working interest, operated by us.
- 22 gross (0.1 net) horizontal wells operated by other producers.

Additionally, at December 31, 2019, we had 19 net horizontal proved developed non-producing wells, and 68 gross horizontal wells (65.5 net) that were drilled and uncompleted or in the process of being completed. The shallow vertical wells and wells operated by other producers were primarily acquired in conjunction with leasehold acreage acquisitions.

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, 2019. A majority of our developed acreage is subject to liens securing the Credit Facility. Approximately 70% of our net Marcellus acreage and 71% of our net Utica acreage is held by production. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this table.

	Developed Acres		Undeveloped Acres		Total Acres	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Marcellus Shale	149,777	148,098	343,269	302,535	493,046	450,633
Utica Shale	44,989	40,800	55,873	50,014	100,862	90,814
Total	194,766	188,898	399,142	352,549	593,908	541,447

The following table provides a summary of our current gross and net acreage by county in the Marcellus Shale and the Ohio Utica Shale in which we own an interest as of December 31, 2019.

	Marcellus	
County, State	**Gross Acres**	**Net Acres**
Doddridge, WV	145,562	133,041
Fayette, PA	5,967	5,454
Gilmer, WV	6,147	5,619
Harrison, WV	96,692	88,374
Lewis, WV	46	42
Marion, WV	5,342	4,882
Monongalia, WV	1,340	1,225
Pleasants, WV	3,692	3,374
Ritchie, WV	72,712	66,457
Tyler, WV	103,543	94,636
Washington, PA	115	105
Westmoreland, PA	4,019	3,673
Wetzel, WV	47,869	43,751
Total Marcellus Shale	493,046	450,633
	Ohio Utica	
	Gross Acres	**Net Acres**
Belmont, OH	7,653	5,450
Guernsey, OH	3,635	3,158
Monroe, OH	47,024	45,616
Noble, OH	42,496	36,544
Washington, OH	54	46
Total Utica Shale	100,862	90,814
Total Marcellus and Utica Shales	593,908	541,447

Undeveloped Acreage Expirations

The following table sets forth our total gross and net undeveloped acres as of December 31, 2019 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates, or unless the leases containing such acreage are extended or renewed.

	Marcellus		Ohio Utica		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
2020	28,432	25,987	15,001	13,300	43,433	39,287
2021	35,209	32,180	7,091	5,984	42,300	38,164
2022	41,719	38,131	5,413	4,371	47,132	42,502

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2017, 2018 and 2019. 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,					
	2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net
Marcellus						
Development wells:						
Productive	112	111	136	134	117	116
Dry	—	—	—	—	—	—
Total development wells	112	111	136	134	117	116
Exploratory wells:						
Productive	1	1	2	2	8	8
Dry	—	—	—	—	—	—
Total exploratory wells	1	1	2	2	8	8
Utica						
Development wells:						
Productive	4	4	17	17	6	6
Dry	—	—	—	—	—	—
Total development wells	4	4	17	17	6	6
Exploratory wells:						
Productive	18	18	8	8	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	18	18	8	8	—	—
Total						
Development wells:						
Productive	116	115	153	151	123	122
Dry	—	—	—	—	—	—
Total development wells	116	115	153	151	123	122
Exploratory wells:						
Productive	19	19	10	10	8	8
Dry	—	—	—	—	—	—
Total exploratory wells	19	19	10	10	8	8

The figures in the table above do not include 68 gross wells (65 net) that were drilled and uncompleted or in the process of being completed at December 31, 2019.

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, 2019, our firm sales commitments through 2024 included:

Year Ending December 31,	Volume of Natural Gas (MMBtu/d)	Volume of Ethane (Bbl/day)	Volume of C3+ NGLs (Bbl/day)
2020	1,030,000	46,500	55,000
2021	900,000	76,500	23,000
2022	780,000	96,500	5,000
2023	690,000	96,500	5,000
2024	600,000	91,500	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."

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. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production. Our relationship with Antero Midstream allows us to obtain the necessary gathering and compression capacity for our production and we have leveraged our relationship with Antero Midstream to support our growth. For the years ended December 31, 2018 and 2019, Antero Midstream spent approximately $444 million and $316 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, 2019, Antero Midstream owned and operated 324 miles of gas gathering pipelines in the Marcellus Shale. We also have access to additional low-pressure and high-pressure pipelines owned and operated by third parties. As of December 31, 2019, Antero Midstream owned and operated 17 compressor stations and we utilized 12 additional third-party compressor stations in the Marcellus Shale. The gathering, compression, and dehydration services provided by third parties are contracted on a fixed-fee basis.

As of December 31, 2019, in the Utica Shale Antero Midstream owned and operated 110 miles of low-pressure and high-pressure gathering pipelines and Antero Resources owned and operated eight miles of high-pressure pipelines. As of December 31, 2019, Antero Midstream owned and operated two compressor stations and we utilized four additional third-party compressor stations in the Utica Shale.

Natural Gas Processing

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

NGLs are valuable commodities once removed from the natural gas stream in a cryogenic processing facility yielding y-grade liquids. Y-grade liquids are then fractionated, thereby breaking up the y-grade liquid into its key components. Fractionation refers to the process by which a 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 region 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.

As of December 31, 2019, we had contracted with MarkWest Energy Partners L.P. to provide cryogenic processing capacity for our Marcellus and Utica Shales production as follows:

	Plant Processing Capacity (MMcf/d)	Contracted Firm Processing Capacity (MMcf/d)	Completion Status
Marcellus Shale:			
Sherwood 1	200	200	In service
Sherwood 2	200	200	In service
Sherwood 3	200	200	In service
Sherwood 4	200	200	In service
Sherwood 5	200	200	In service
Sherwood 6	200	200	In service
Sherwood 7	200	200	In service
Sherwood 8	200	200	In service
Sherwood 9	200	200	In service
Sherwood 10	200	200	In service
Sherwood 11	200	200	In service
Sherwood 12	200	200	In service
Sherwood 13	200	200	In service
Smithburg 1	200	200	2Q 2020*
Marcellus Shale Total	2,800	2,800	
Utica Shale:			
Seneca 1	200	150	In service
Seneca 2	200	50	In service
Seneca 3	200	200	In service
Seneca 4	200	200	In service
Utica Shale Total	800	600	

* Anticipated in-service date

Antero Midstream owns a 50% interest in the Joint Venture which owns certain of the existing and future Sherwood gas processing plants and a 33 1/3% interest in two fractionation facilities located at the Hopedale complex in Harrison County, Ohio. The Joint Venture's processing investment began with the seventh plant at the Sherwood facility and continues through Sherwood 13 and Smithburg 1 in the table above. The Joint Venture provides processing services to us under a long-term, fixed-fee arrangement, subject to annual CPI-based adjustments.

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:

- 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. We have 290,000 MMBtu per day of firm transportation on MGT. We have 310,000 MMBtu per day of firm transportation on NGPL. Both of these contracts deliver gas to the Chicago city gate area. In addition, we have 200,000 MMBtu per day of firm transportation on ANR to deliver 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.
- To access the Gulf Coast market and Eastern Regional markets, we have firm transportation contracts with various pipelines. These contracts include firm capacity on the Columbia Gas Transmission pipeline ("TCO"), Columbia Gulf Transmission pipeline ("Columbia Gulf"), Tennessee Gas Pipeline ("Tennessee"), Energy Transfer Rover Pipeline ("ET Rover"), ANR Pipeline ("ANR-Gulf"), Equitrans pipeline ("EQT"), and DTE Energy's Stonewall Gas Gathering ("SGG") and Appalachia Gathering System ("AGS"). This 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.
    - We have several firm transportation contracts on TCO for volumes that total to approximately 584,000 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 of firm capacity on Columbia Gulf, which provides access to the Gulf Coast markets. These contracts expire at various dates from 2021 through 2058.
    - We have a firm transportation contract with SGG for 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. We have a firm transportation contract with TCO to transport natural gas in the western and eastern direction on TCO's WB system. The firm transportation contract on TCO's WB system provides firm capacity in the western direction for 800,000 MMBtu per day. This west directed firm capacity provides access to the local Appalachia market and the Gulf Coast market via the Columbia Gulf or Tennessee pipelines. The firm transportation contract on TCO's WB system also provides firm capacity in the eastern direction, which delivers natural gas to the Cove Point LNG facility, for 330,000 MMBtu per day. These contracts expire at various dates from 2033 through 2038.
    - We have a firm transportation contract for 790,000 MMBtu per day on Tennessee to deliver natural gas from the Broad Run interconnect on TCO's WB system to the Gulf Coast market. This contract expires in 2033.
    - We have a firm transportation contract for 600,000 MMBtu per day on ANR-Gulf to deliver natural gas from West Virginia and Ohio to the U.S Gulf Coast market. This contract expires in 2045.
    - We have a firm transportation contract for 800,000 MMBtu per day on the ET Rover Pipeline, which connects the Marcellus and Utica Shales' assets to Midwest and Gulf Coast markets via our existing firm transportation on ANR Chicago and ANR Gulf. This contract expires in 2033.
    - We have firm transportation contracts for 250,000 MMBtu per day on EQT to deliver Marcellus natural gas to Tetco M2 and other various delivery points. These contracts expire at various dates from 2022 through 2025.
    - We have firm transportation contracts for 275,000 MMBtu per day on the DTE AGS to deliver Marcellus natural gas to TETCO M2 and other various local delivery points. These contracts expire in 2023.
    - We have firm transportation contracts for 700,000 MMBtu per day on MXP to deliver 517,000 MMBtu per day to TCO IPP and 183,000 MMBtu per day continues on GXP to Leach, Kentucky and deliver to the U.S. Gulf Coast. These contracts expire in 2033.

- We have a firm transportation contract for 20,000 Bbl per day on the Enterprise Products Partners ATEX pipeline ("ATEX"), to take ethane from Appalachia to Mont Belvieu, Texas. The ATEX firm transportation commitment expires in 2028.

- We have a firm transportation contract for 11,500 Bbl per day on the Sunoco pipeline (or "Mariner East 2") to take ethane from Houston, Pennsylvania to Marcus Hook, Pennsylvania. This contract began November 2018. We also have a firm transportation contract on Mariner East 2 to take a combination of 50,000 Bbl per day of propane and butane from Hopedale, Ohio to Marcus Hook, Pennsylvania, which began February 2019. This contract increases 5,000 Bbl per day each year from 2020 – 2022, resulting in an ultimate total of 65,000 Bbl per day. These contracts expire on the tenth anniversary from the in-service date. 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 2020 annual production guidance, we estimate that we could incur annual net marketing costs of $0.10 per Mcfe to $0.12 per Mcfe in 2020 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.

Water Handling and Treatment Operations

On September 23, 2015, we contributed (i) all of the outstanding limited liability company interests of Antero Water LLC to Antero Midstream and (ii) all of the assets, contracts, rights, permits and properties we owned or leased and used primarily in connection with the construction, ownership, operation, use or maintenance of our advanced wastewater treatment facility in Doddridge County, West Virginia, to Antero Treatment LLC, a wholly owned subsidiary of Antero Midstream. Our relationship with Antero Midstream allows 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 Marcellus and Utica Shales. These systems consist of permanent buried pipelines, movable surface pipelines and fresh water storage facilitates, as well as pumping stations to transport the fresh water throughout the pipeline networks. To the extent necessary, the surface pipelines are moved to well pads for service completion operations in concert with our drilling program. As of December 31, 2019, Antero Midstream had the ability to store 5.8 million barrels of fresh water in 38 impoundments located throughout our leasehold acreage in the Marcellus and Utica Shales. Due to the extensive geographic distribution of Antero Midstream's water pipeline systems in both West Virginia and Ohio, 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, 2019, Antero Midstream owned and operated 149 miles of buried fresh water pipelines and 98 miles of movable surface fresh water pipelines in the Marcellus Shale, as well as 26 fresh water storage facilities equipped with transfer pumps. As of December 31, 2019, Antero Midstream owned and operated 54 miles of buried fresh water pipelines and 31 miles of movable surface fresh water pipelines in the Utica Shale, as well as 12 fresh water storage facilities equipped with transfer pumps.

We recently announced certain efficiency improvements and water initiatives, which are expected to reduce the amount of fresh water needed to complete our operations. Through Antero Midstream, we have also commenced operations to recycle and reuse a portion of our flowback and produced water through blending.

Major Customers

For the year ended December 31, 2019, sales to Sabine Pass Liquefaction, LLC and WGL Midstream accounted for approximately 16% and 15% of our total product revenues, respectively. For the year ended December 31, 2018, sales to Mercuria Energy America, Inc. and Tenaska Marketing Ventures accounted for approximately 14% and 13% of our total product revenues, respectively. For the year ended December 31, 2017, sales to Tenaska Marketing Ventures and WGL Midstream accounted for approximately 20% and 14% of our total product revenues, respectively.

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

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 materially 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, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers, and marketers with which we compete.

Regulation of 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 the power to prorate production to the market demand for oil and gas. 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, or FERC, under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or 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, or CEA, and the Federal Trade Commission, or 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, or 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 2020, FERC issued an order (Order No. 865) increasing the maximum civil penalty amounts under the NGA and NGPA to adjust for inflation. FERC may now assess civil penalties under the NGA and NGPA of up to $1,291,894 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 $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, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of 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, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling 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, or 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, or 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 U.S. Environmental Protection Agency, or 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, legal challenges to the new rule are expected, and multiple challenges to the EPA's prior rulemakings remain pending. 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. 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, or 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 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, the reduction of volatile organic compound ("VOC") emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." 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 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, or 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, or 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 volatile organic compounds 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, or NSPS Quad O, to include previously unregulated equipment within the oil and natural gas source category. Following the change in presidential administrations, there have been attempts to modify these regulations. Most recently, in August 2019, the EPA proposed amendments to the 2016 standards that, among other things, would remove sources in the transmission and storage segment from the oil and natural gas source category and rescind the methane-specific requirements applicable to sources in the production and processing segments of the industry. As an alternative, the EPA also proposed to rescind the methane-specific requirements that apply to all sources in the oil and natural gas industry, without removing the transmission and storage sources from the current source category. Under either alternative, the EPA plans to retain emissions limits for VOCs for covered oil and gas facilities and equipment. Legal challenges to any final rulemaking that rescinds the 2016 standards are expected. As a result of these developments, substantial uncertainty exists with respect to implementation of the EPA's 2016 methane rule. However, 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 air emissions by: (1) monitoring the science of climate change and air quality, (2) addressing stakeholder inquiries regarding our position on climate change, methane emissions and air quality matters, (3) monitoring our measures to reduce methane and air emissions, and (4) overseeing development of methane and air emission reductions from activities, including implementation of best-management practices and new technology.

We have been making efforts to reduce methane emissions since March 2005, when we engaged local community groups in Colorado regarding our former activities in the Piceance Basin in discussions on how to minimize air emission impacts from our operations. In addition, we have been performing green completions since before the EPA's NSPS Quad O rules became effective in January 2015. In particular, we implemented green completions on our former Piceance Basin assets in Colorado in July 2011, using equipment that our personnel helped design. After initial testing confirming the viability and effectiveness of the units, we implemented their use in the Appalachian Basin Marcellus Shale play in 2012 and later in the Utica Shale play. We have a long history of managing methane emissions from our operations, as demonstrated by our early use of green completions.

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 (VRTs) and Vapor Recovery Units (VRUs), 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 (OGI) Forward Looking Infrared Radar (FLIR) 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.

In 2017, we joined the EPA Natural Gas Star Program. The EPA Natural Gas STAR Program 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. In 2018, we became members of ONE Future, a voluntary industry collective that seeks to reduce methane emission intensity across the natural gas supply chain. Also in 2018, we began participation in the American Petroleum Institute's 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: 1) evaluate our methane emission reduction opportunities, 2) implement methane reduction projects where feasible, and 3) annually report our methane emissions and/or our methane reduction activities.

For years 2017 and 2018, we published an annual Corporate Social Responsibility (CSR) report, which highlights all of our environmental program improvements and initiatives. As highlighted in our report, our methane leak loss rate is 0.06%, well below the industry target of 1%.

During 2019, our 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) Explored the use of lockdown thief hatches on storage tanks.

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) Implementation and 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) during initial well 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 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 bleed to low bleed pneumatics at all new production facilities. We installed air controlled pneumatics on some 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, governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States' withdrawal from the Paris Agreement in November 2020. 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 exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

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 dense 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, or the 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.

Certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Because this report, in keeping with several others that have been conducted, did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

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. 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 follow 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, or 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, or 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, or the 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 2019, nor do we anticipate that such expenditures will be material in 2020.

Employees

As of December 31, 2019, we had 547 full-time employees, including 40 employees in executive, finance, treasury, legal and administration, 20 in information technology, 16 in geology, 219 in production and engineering, 146 in midstream and water, 63 in land, and 43 in accounting and internal audit. Our future success will depend partially on our ability to attract, retain, and motivate qualified personnel. 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 satisfactory. We utilize the services of independent contractors to perform various field and other services.

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.

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 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 following the recent coronavirus outbreaks);
- 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 $4.25 per MMBtu to a low of $1.75 per MMBtu in 2019, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $66.24 per barrel to a low of $46.31 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 $1.0 billion impairment charge we recognized in the third quarter of 2019. Reductions in cash flows from lower commodity prices have required us to incur additional borrowings and reduce our capital spending and could further 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 for our storage assets 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.

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 "—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 and qualified personnel or in obtaining 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 or oil in commercially viable quantities.

Properties that we decide to drill that do not yield natural gas or oil in commercially viable quantities may adversely affect our financial condition, results of operations and cash flows. There is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of 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 may hinder our access to natural gas, NGLs, and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas, NGLs, and oil transportation arrangements 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 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 pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and other transportation services owned and operated by third parties, including Antero Midstream. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs, and oil pipelines or gathering or processing system capacity or third-party transportation services, including with respect to services provided to us by Antero Midstream. In addition, if natural gas, NGLs, or oil quality specifications for the pipelines with which we connect change so as to restrict our ability to transport our production, our access to natural gas, NGLs, and oil markets could be impeded. If our production becomes shut in 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.

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.

At December 31, 2019, 38% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 7.1 Tcfe of estimated proved undeveloped reserves will require an estimated $2.6 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 PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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 $1.3 billion in 2019. Our board of directors has approved a capital budget for 2020 of $1.2 billion that includes $1.15 billion for drilling and completion and $50 million for leasehold expenditures. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations, borrowings under the Credit Facility, our asset sales program and dividends from Antero Midstream; 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 grow production. Furthermore, we have previously announced our intention to retire a portion of our outstanding senior notes. Although we intend to finance such retirement primarily with proceeds from asset sales, any borrowings incurred under the Credit Facility for such retirement or other refinancings of debt may limit our ability to fund our capital budget. 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 flow 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 flow 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.

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") 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 growth plans, the terms of our agreements with Antero Midstream and its subsidiaries and the pursuit of potentially competitive business activities or business opportunities.

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

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness, including the senior notes. For example, we recently announced an asset sale program, the proceeds of which will be 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 senior unsecured notes, 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, 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. 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 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 $4.5 billion, and lender commitments under the Credit Facility are $2.64 billion. Our borrowing base is redetermined by the lenders each April based on certain factors, including our reserves and hedge position, with the next borrowing base redetermination scheduled to occur in April 2020. 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 corporate credit rating, similar to the December 2019 downgrade by Moody's Investors Services, 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, including the market for senior unsecured notes, 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 2019, the market for senior unsecured notes was unfavorable for high-yield issuers such as us. Our plans for growth may require access to the capital and credit markets, including the ability to issue senior unsecured notes. Although the market for high-yield debt securities experienced periods of improvement in 2019, if the high-yield market deteriorates, or if we are unable to access alternative means of debt or equity financing on acceptable terms, 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.

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, 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 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 an 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 2019, we had estimated average outstanding borrowings under the Credit Facility of approximately $264 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 $2.6 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. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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 natural gas 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 and could result in operating costs exceeding revenues.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2019, we had entered into forward swap contracts for approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production through December 31, 2023 and basis swap contracts for approximately 0.2 Tcfe through December 31, 2024. Historically, we have realized a significant benefit from our hedge positions. For example, for the years ended December 31, 2018 and 2019, we received approximately $613 million and $325 million, respectively, in revenues from cash settled derivatives pursuant to our hedging arrangements, including $370 million for certain natural gas hedges that were monetized prior to their contractual settlement dates during the year ended December 31, 2018. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2018 and 2019 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, since we have financial derivatives in place in order 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. Approximately 70% of our estimated production for 2020 is hedged through either forward swaps or basis swaps. 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. 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.

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

As of December 31, 2019, the estimated fair value of our commodity net derivative contracts was approximately $746 million, primarily including the following net asset values by bank counterparty: Wells Fargo - $215 million; JP Morgan - $134 million; Morgan Stanley - $121 million; Citigroup - $117 million; Scotiabank - $58 million; Canadian Imperial Bank of Commerce - $44 million; PNC - $29 million; BNP Paribas - $21 million; Natixis - $10 million; and SunTrust $7 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 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.

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 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, our gas processing, gathering, and compression services agreements expire at various dates from 2020 to 2038. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. As of December 31, 2019, our long-term contractual obligations under agreements with minimum volume commitments totaled over $18 billion over the term of the contracts. If we have insufficient production to meet the minimum volumes, 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.

Based on current projected 2020 annual production guidance, we estimate that we could incur annual net marketing costs of $0.10 per Mcfe to $0.12 per Mcfe in 2020 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 are able to 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 are able to offer us more favorable pricing or more efficient service.

If additional takeaway pipelines under construction or other pipeline projects are not completed, our future growth may be limited.

We have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in each of our core operating areas to accommodate our current development plan. Any unavailability of existing takeaway pipelines could cause us to curtail our future development and production plans, which could adversely affect our business, financial condition and results of operations.

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. For example, Antero Midstream idled its wastewater treatment facility and related landfill in September 2019, which limits Antero Midstream's available outlets to dispose of our produced water. 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.

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 dense 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.

Certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. Because the report did not find a direct link between hydraulic fracturing and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

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. 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.

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.

In order 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.

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 that would be 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 growth 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 uncertain factors, 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 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, 2019, we had 2,385 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 in order 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."

Approximately 65% 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 65% 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 687 Bcfe related to such acreage that is subject to renewal prior to drilling. In addition, approximately 30% and 29% of our natural gas leases related to our Marcellus and Utica acreage, respectively, 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."

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.

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. At December 31, 2019, 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 natural gas 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.

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.

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.

Our delivery of natural gas, NGLs, and oil depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing and fractionation facilities and the availability of other third-party transportation services. The capacity of transmission, gathering and processing and fractionation facilities and 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 cyber-attacks on such pipelines and facilities or service interruptions due to gas quality, could result in adverse consequences to us, such as 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.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, 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 before attempting to acquire a lease in a specific mineral interest. 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. Additionally, there are claims against us alleging that certain acquired leases that are held by production are invalid due to production from the producing horizons being insufficient to hold title to the formation rights that we have purchased. 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.

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 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.

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 gas 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.

Conservation measures and technological advances could reduce demand for oil and gas products.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas products, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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 ($297 million at December 31, 2019). 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, 2019 accounted for approximately 16% 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.

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 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.

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. 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.

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.

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

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. Although the FERC has not made any formal determinations with respect to any of our facilities, we believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis. Therefore, the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress, and such increased regulation could cause our revenues to decline and operating expenses to increase, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

Under the EPAct of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,291,894 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.

In response to findings that emissions of carbon dioxide, methane and other 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 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. 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 of hydraulically fractured 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.

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 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 to include previously unregulated equipment within the oil and natural gas source category. There have been several attempts to delay or modify these regulations. Most recently, in August 2019, the EPA proposed amendments to the 2016 standards that, among other things, would remove sources in the transmission and storage segment from the oil and gas source category and rescind the methane-specific requirements applicable to sources in the production and processing segments of the industry. As an alternative, the EPA also proposed to rescind the methane-specific requirements that apply to all sources in the oil and gas industry, without removing the transmission and storage sources from the current source category. Under either alternative, the EPA plans to retain emissions limits for VOCs. Legal challenges to any final rulemaking that rescinds the 2016 standards are expected. As a result of the foregoing, substantial uncertainty exists with respect to implementation of the EPA's 2016 methane rule. However, 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.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of federal legislation in recent years. Nevertheless, increasing scientific and public concern over the threat of climate change has increased the possibility of political action related to climate change. For example, various pledges have been made by candidates running for the Democratic nomination for President of the United States in 2020. These have included promises to pursue actions that would be adverse to oil and gas production and processing activities, though the extent of any such actions cannot be predicted at this time.

In the absence of federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions or transitions to alternative forms of energy could also adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Depending on the severity of any such limitations, the effect on the value of our reserves could be significant.

On an international level, the United States is one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets ("Paris Agreement"). The Paris Agreement was signed by the United States in April 2016 and entered into force on November 4, 2016; however, the Paris Agreement does not impose any binding obligations on its participants. Moreover, in November 2019, the United States formally initiated the yearlong process to withdraw from the Paris Agreement. However, the United States may subsequently choose to reenter the Paris Agreement or a separately negotiated agreement, though the terms of any such agreement are uncertain at this time.

Separately, increased attention to climate change risks has increased the possibility of claims brought by public and private entities against oil and gas companies in connection with their GHG emissions. While we are not currently party to any such private litigation, we could be named in future actions making similar claims of liability. Moreover, 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 the company's causation of or contribution to the asserted damage, or to other mitigating factors.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Increased scrutiny because of climate change related concern could result in a loss of certain investors. In addition, institutional lenders may, of their own accord, elect 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.

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.

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.

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 able to compete successfully 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.

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.

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 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.

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 and hinder our ability to grow.

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 Credit Facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. The Credit Facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

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 and reduce our future growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our 2020 business plan, we considered allocating capital and other resources to various aspects of our businesses, including well development, reserve acquisitions, exploratory activities, midstream infrastructure, corporate items, repayment of indebtedness and other alternatives. We also considered our likely sources of capital, including potential asset sales. Notwithstanding the determinations made in the development of our 2020 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, appropriate rate of reserve development, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2020 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, various factors including prevailing market conditions 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. Joint venture arrangements may restrict our operational and corporate flexibility. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may have little control over, and our joint venture partners may not satisfy their obligations to the joint venture. 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.

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 dividends per share of our common stock, 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.

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. 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.

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.

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 only 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.

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 Delaware General Corporation Law (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. 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 have elected not to be subject to the provisions of Section 203 of 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 NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- prior to such time, the business combination or the transaction which resulted in the stockholder becoming an interested stockholder is approved by our board of directors;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced (excluding certain specified shares); or
- on or after such time the business combination is approved by our board of directors and authorized at a meeting of stockholders by the holders of at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

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

We may 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.

Final regulations relating to and interpretations of provisions of the Tax Cuts and Jobs Act may vary from our current interpretation of such legislation.

The U.S. federal income tax legislation enacted in Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act, is highly complex and subject to interpretation. The presentation of our financial condition and results of operations is based upon our current interpretation of the provisions contained in the Tax Cuts and Jobs Act. The Treasury Department and the Internal Revenue Service have issued, and are expected to continue to issue, final regulations and additional interpretive guidance with respect to the provisions of the Tax Cuts and Jobs Act. Any significant variance of our current interpretation of such provisions from any future final regulations or interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

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, 2019, we have U.S. federal and state NOL carryforwards of $2.2 billion and $2.0 billion, respectively, some of which expire at various dates from 2032 to 2038 while others have no expiration date. We 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 the current expectation that our NOL carryforwards will not become subject to future limitations under Section 382 of the Internal Revenue Code of 1986 or otherwise. Additionally, 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 limitations, our future tax liability may be greater than expected.

Changes to state tax laws in response to the Tax Cuts and Jobs Act or that impose new or increased taxes or fees on natural gas and oil extraction may result in an increase in the state taxes we pay.

Currently, many states conform their calculation of corporate taxable income to the calculation of corporate taxable income at the U.S. federal level. Due to changes to U.S. federal income tax laws as a result of the Tax Cuts and Jobs Act, certain states may change or modify the calculation of corporate taxable income at the state level. Any resulting increase in costs due to such changes could have an adverse effect on our financial position, results of operations and cash flows. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on natural gas and oil extraction, which could negatively affect our future cash flows and financial condition.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

The information required by this item is included in Note 15 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 7, 2020, our common stock was held by 168 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 [(1)]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans [(2)]	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plan
October 1, 2019 - October 31, 2019	3,968	$ 2.65	—	$ 448,351,414
November 1, 2019 - November 30, 2019	7,237,496	$ 2.58	7,237,496	$ 429,683,121
December 1, 2019 - December 31, 2019	1,092,175	$ 2.00	1,092,175	$ 427,503,572
Total	8,333,639	$ 2.50	8,329,671	

(1) The total number of shares purchased includes 3,968 shares repurchased in October 2019, 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. There were no such repurchases in November or December.

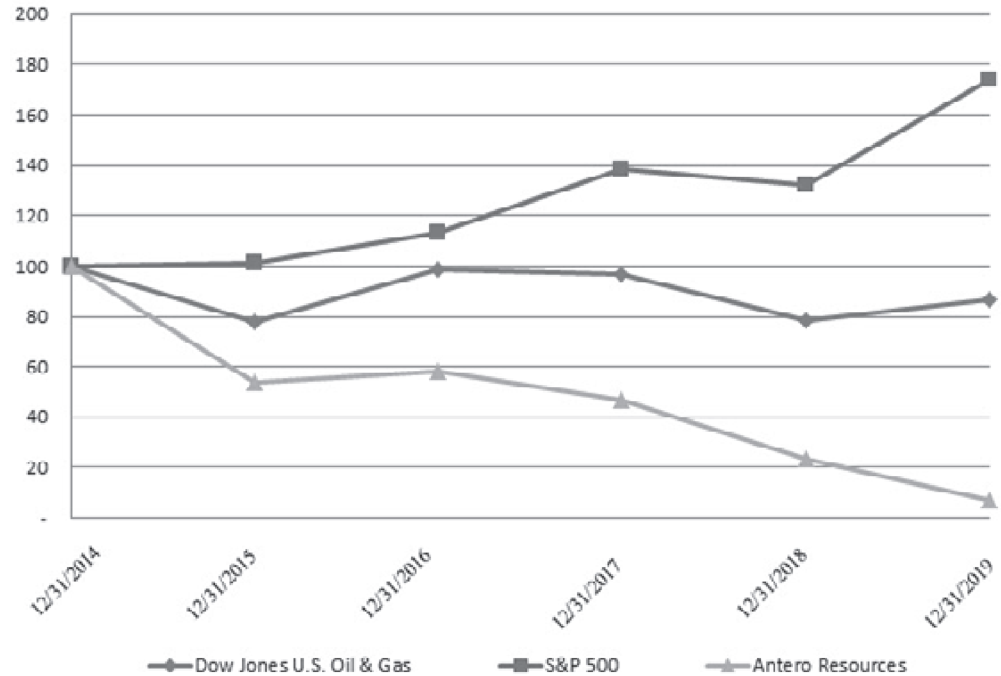
(2) In October 2018, our Board of Directors authorized a $600 million share repurchase program. During the three months ended December 31, 2019, we repurchased 8,329,671 shares of common stock under this program for a total of $21 million, or an average of $2.50 per share, which shares were thereafter cancelled.

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 5.375% senior notes due 2021, 5.125% senior notes due 2022, 5.625% senior notes due 2023, and 5.00% senior notes due 2025 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, 2014 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 5 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, 2017, 2018 and 2019 and the balance sheet data as of December 31, 2018 and 2019 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, 2015 and 2016 and the balance sheet data as of December 31, 2015, 2016 and 2017 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 years ended December 31, 2016 and 2015 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.

The statement of cash flows data for the years ended December 31, 2015 has been recast to present the effects of the adoption of ASU No. 2016-09, *Stock Compensation–Improvements to Employee Share-Based Payment Accounting*, in 2016, which requires that income taxes withheld upon settlement of share-based payment awards be classified as financing activities on the statement of cash flows.

Our historical results of operations also 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, 2015	2016	2017	2018	2019
Statement of operations data:					
Operating revenues and other:					
Natural gas sales	$ 1,039,892	1,260,750	1,769,284	2,287,939	2,247,162
Natural gas liquids sales	264,483	432,992	870,441	1,177,777	1,219,162
Oil sales	70,753	61,319	108,195	187,178	177,549
Commodity derivative fair value gains (losses)	2,381,501	(514,181)	658,283	(87,594)	463,972
Gathering, compression, and water handling and treatment	22,000	12,961	12,720	21,344	4,478
Marketing	176,229	393,049	258,045	458,901	292,207
Marketing derivative fair value gains (losses)	—	—	(21,394)	94,081	—
Gain on sale of assets	—	97,635	—	—	—
Other income	—	—	—	—	4,160
Total operating revenues and other	3,954,858	1,744,525	3,655,574	4,139,626	4,408,690
Operating expenses:					
Lease operating	36,011	50,090	89,057	136,153	145,720
Gathering, compression, processing, and transportation	659,361	882,838	1,095,639	1,339,358	2,146,647
Production and ad valorem taxes	78,325	66,588	94,521	126,474	125,142
Marketing	299,062	499,343	366,281	686,055	549,814
Exploration	3,846	6,862	8,538	4,958	884
Impairment of oil and gas properties	104,321	162,935	159,598	549,437	1,300,444
Impairment of midstream assets	—	—	23,431	9,658	14,782
Depletion, depreciation, and amortization	709,763	809,873	824,610	972,465	914,867
Loss on sale of assets	—	—	—	—	951
Accretion of asset retirement obligations	1,655	2,473	2,610	2,819	3,762
General and administrative (including $97,877, $102,421, $103,445, $70,413 and $23,559 of equity-based compensation expense in 2015, 2016, 2017, 2018, and 2019, respectively)	233,697	239,324	251,196	240,344	178,696
Contract termination and rig stacking	38,531	—	—	—	14,026
Total operating expenses	2,164,572	2,720,326	2,915,481	4,067,721	5,395,735
Operating income (loss)	1,790,286	(975,801)	740,093	71,905	(987,045)
Other income (expenses):					
Water earnout	—	—	—	—	125,000
Equity in earnings (loss) of unconsolidated affiliate	—	485	20,194	40,280	(143,216)
Loss on the sale of equity investment shares	—	—	—	—	(108,745)
Interest expense, net	(234,400)	(253,552)	(268,701)	(286,743)	(228,111)
Impairment of equity investments	—	—	—	—	(467,590)
Gain on deconsolidation of Antero Midstream Partners LP	—	—	—	—	1,406,042
Gain (loss) on early extinguishment of debt	—	(16,956)	(1,500)	—	36,419
Total other income (expenses)	(234,400)	(270,023)	(250,007)	(246,463)	619,799
Income (loss) before income taxes	1,555,886	(1,245,824)	490,086	(174,558)	(367,246)
Provision for income tax (expense) benefit	(575,890)	496,376	295,051	128,857	74,110
Net income (loss) and comprehensive income (loss) including noncontrolling interest	979,996	(749,448)	785,137	(45,701)	(293,136)
Net income and comprehensive income attributable to noncontrolling interest	38,632	99,368	170,067	351,816	46,993
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 941,364	(848,816)	615,070	(397,517)	(340,129)
Income (loss) per common share—basic	3.43	(2.88)	1.95	(1.26)	(1.11)
Income (loss) per common share—dilutive	3.43	(2.88)	1.94	(1.26)	(1.11)

(in thousands)	Year Ended December 31, 2015	2016	2017	2018	2019
Balance sheet data (at period end):					
Cash and cash equivalents	$ 23,473	31,610	28,441	—	—
Other current assets	1,224,763	370,977	804,646	806,613	922,885
Total current assets	1,248,236	402,587	833,087	806,613	922,885
Natural gas properties, at cost (successful efforts method):					
Unproved properties	1,996,081	2,331,173	2,266,673	1,767,600	1,368,854
Producing properties	8,211,106	9,549,671	11,096,462	12,705,672	11,859,817
Water handling and treatment systems	565,616	744,682	946,670	1,013,818	—
Gathering systems and facilities	1,502,396	1,723,768	2,050,490	2,470,708	5,802
Other property and equipment	46,415	41,231	57,429	65,842	71,895
	12,321,614	14,390,525	16,417,724	18,023,640	13,306,368
Less accumulated depletion, depreciation, and amortization	(1,589,372)	(2,363,778)	(3,182,171)	(4,153,725)	(3,327,629)
Property and equipment, net	10,732,242	12,026,747	13,235,553	13,869,915	9,978,739
Other assets	2,135,015	1,826,216	1,192,850	842,936	4,295,945
Total assets	$ 14,115,493	14,255,550	15,261,490	15,519,464	15,197,569
Current liabilities	$ 707,270	817,388	762,096	853,540	1,040,139
Long-term indebtedness	4,668,782	4,703,973	4,800,090	5,461,688	3,758,868
Other long-term liabilities	1,452,763	1,005,611	823,168	716,759	3,427,819
Total equity	7,286,678	7,728,578	8,876,136	8,487,477	6,970,743
Total liabilities and equity	$ 14,115,493	14,255,550	15,261,490	15,519,464	15,197,569
Other financial data:					
Net cash provided by operating activities	$ 1,015,812	1,241,256	2,006,291	2,081,987	1,103,458
Net cash used in investing activities	(2,298,159)	(2,395,138)	(2,461,630)	(2,350,724)	(1,041,490)
Net cash provided by financing activities	1,059,841	1,162,019	452,170	240,296	557,564
Capital expenditures	2,347,909	2,495,429	2,216,753	2,210,586	1,422,155
Adjusted EBITDAX	1,112,331	1,384,442	1,244,394	1,717,120	1,247,671

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, 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 equity investment shares, equity in earnings or loss of unconsolidated affiliates, water earnout, simplification transaction fees, gain or loss on sale of assets and Antero Midstream Partners 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 5 to the consolidated financial statements for more information on our equity 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; and

- 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. Adjusted EBITDAX is also 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 in order to provide comparability with the current structure of Antero Resources as Antero Resources as 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, 2015	2016	2017	2018	2019
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$	941,364	(848,816)	615,070	(397,517)	(340,129)
Net income and comprehensive income attributable to noncontrolling interests		38,632	99,368	170,067	351,816	46,993
Commodity derivative fair value (gains) losses[1]		(2,381,501)	514,181	(658,283)	87,594	(463,972)
Gains on settled commodity derivatives[1]		856,572	1,003,083	213,940	243,112	325,090
Marketing derivative fair value (gains) losses[1]		—	—	21,394	(94,081)	—
Gains on settled marketing derivatives[1]		—	—	—	72,687	—
(Gain) loss on sale of assets		—	(97,635)	—	—	951
Gain on deconsolidation of Antero Midstream Partners LP		—	—	—	—	(1,406,042)
Interest expense		234,400	253,552	268,701	286,743	228,111
(Gain) loss on early extinguishment of debt		—	16,956	1,500	—	(36,419)
Provision for income tax expense (benefit)		575,890	(496,376)	(295,051)	(128,857)	(74,110)
Depletion, depreciation, amortization, and accretion		711,418	812,346	827,220	975,284	918,629
Impairment of oil and gas properties		104,321	162,935	159,598	549,437	1,300,444
Impairment of midstream assets		—	—	23,431	9,658	14,782
Impairment of equity investments		—	—	—	—	467,590
Exploration expense		3,846	6,862	8,538	4,958	884
Equity-based compensation expense		97,877	102,421	103,445	70,413	23,559
Equity in (earnings) loss of unconsolidated affiliate		—	(485)	(20,194)	(40,280)	143,216
Distributions from unconsolidated affiliates		—	7,702	20,195	46,415	157,956
State franchise taxes		72	50	—	—	—
Contract termination and rig stacking		38,531	—	—	—	14,026
Loss on sale of equity investment shares		—	—	—	—	108,745
Water earnout		—	—	—	—	(125,000)
Simplification transaction fees		—	—	—	—	15,482
		1,221,422	1,536,144	1,459,571	2,037,382	1,320,786
Net income and comprehensive income attributable to noncontrolling interests		(38,632)	(99,368)	(170,067)	(351,816)	(46,993)
Antero Midstream Partners interest expense, net[2]		(5,832)	(21,097)	(36,370)	(61,766)	(16,815)
Antero Midstream Partners depreciation, accretion of ARO and accretion of contingent consideration[2]		(71,236)	(116,350)	(133,038)	(37,129)	(21,770)
Antero Midstream Partners impairment[2]		—	—	(23,431)	(5,188)	(6,982)
Antero Midstream Partners equity-based compensation expense[2]		(19,025)	(26,049)	(27,283)	(21,073)	(2,477)
Antero Midstream Partners equity in earnings of unconsolidated affiliates[2]		—	485	20,194	40,280	12,264
Antero Midstream Partners distributions from unconsolidated affiliates[2]		—	(7,702)	(20,195)	(46,415)	(61,319)
Equity in earnings of Antero Midstream Partners[2]		(47,485)	7,156	43,710	3,664	(15,021)
Distributions from Antero Midstream Partners[2]		73,119	107,364	131,598	159,181	95,183
Antero Midstream Partners loss on extinguishment of debt[2]		—	—	(295)	—	—
Antero Midstream Partners gain on sale[2]		—	3,859	—	—	—
Antero Midstream Partners Simplification transaction fees[2]		—	—	—	—	(9,185)
Antero Midstream Partners related adjustments		(109,091)	(151,702)	(215,177)	(320,262)	(73,115)
Adjusted EBITDAX	$	1,112,331	1,384,442	1,244,394	1,717,120	1,247,671

Reconciliation of our Adjusted EBITDAX to net cash provided by operating activities:

(in thousands)	Year ended December 31, 2015	2016	2017	2018	2019
Adjusted EBITDAX	$ 1,112,331	1,384,442	1,244,394	1,717,120	1,247,671
Antero Midstream Partners related adjustments	109,091	151,702	215,177	320,262	73,115
Interest expense, net	(234,400)	(253,552)	(268,701)	(286,743)	(228,111)
Exploration expense	(3,846)	(6,862)	(8,538)	(4,958)	(884)
Changes in current assets and liabilities	39,498	(32,920)	76,035	(25,423)	35,542
State franchise taxes	(72)	(50)	—	—	—
Proceeds from derivative monetizations	—	—	749,906	370,365	—
Premium paid on derivative contracts	—	—	—	(13,318)	—
Other non-cash items	(6,790)	(1,504)	(1,982)	4,682	(23,875)
Net cash provided by operating activities	$ 1,015,812	1,241,256	2,006,291	2,081,987	1,103,458

(1) The adjustments for the derivative fair value gains and losses and gains on settled derivatives have the effect of adjusting net income (loss) from operations for changes in the fair value of unsettled derivatives, which are recognized at the end of each accounting period. As a result, derivative gains included in the calculation of Adjusted EBITDAX only reflect derivatives that settled during the period. The adjustments do not include proceeds from derivatives monetization.

(2) Amounts reflected are net of any elimination adjustments for intercompany activity and include activity related to Antero Midstream Partners through March 12, 2019 (date of the closing of the Transactions). Effective March 13, 2019, we account for our unconsolidated investment in Antero Midstream using the equity method of accounting. See Note 5 to the consolidated financial statements for further discussion on equity method investments.

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, availability of acquisitions, 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, 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 exploration, development and production 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 profitably grow 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 Marcellus Shale and Utica Shale of the Appalachian Basin. As of December 31, 2019, we held approximately 451,000 net acres in the southwestern core of the Marcellus Shale, primarily in West Virginia, and approximately 91,000 net acres in the core of the Ohio Utica Shale for a total of 541,000 net acres in the Appalachian Basin. In addition, we estimate that approximately 179,000 net acres of our Marcellus Shale leasehold may be prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on approximately 223,000 net acres of our Marcellus Shale leasehold in West Virginia that may be prospective for the dry gas Utica Shale.

As of December 31, 2019, our estimated proved reserves were approximately 18.9 Tcfe, consisting of 11.5 Tcf of natural gas, 652 MMBbl of assumed recovered ethane, 540 MMBbl of C3+ NGLs, and 42 MMBbl of oil. This represents a 5% increase in estimated proved reserves from December 31, 2018. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2019, we had approximately 2,385 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) the gathering and processing of natural gas 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.

Closing of Simplification Transaction and Midstream Stock Repurchase

On March 12, 2019, pursuant to 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, 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. In connection with the Closing, we received $297 million in cash and 158.4 million shares of Antero Midstream's common stock, par value $0.01 per share, in consideration for 98,870,335 common units representing limited partnership interests in Antero Midstream Partners.

Prior to the Closing, our ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and we consolidated Antero Midstream Partners' financial position and results of operations into our consolidated financial statements. The Transactions resulted in the exchange of limited partner interests in Antero Midstream Partners we owned for common stock of Antero Midstream representing an approximate 31% interest. As a result, 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. Because Antero Midstream Partners does not meet the requirements of a discontinued operation, Antero Midstream Partners' results of operations continue to be included in our consolidated statement of operations and comprehensive income (loss) through March 12, 2019.

On December 16, 2019, we sold 19,377,592 shares of Antero Midstream's common stock to Antero Midstream at a price of $5.1606 per share, which shares were thereafter cancelled by Antero Midstream, resulting in aggregate proceeds to us of $100 million. This reduced our interest in Antero Midstream to approximately 28.7% as of December 31, 2019.

Antero Midstream owns, operates and develops midstream energy assets that service our production. Antero Midstream's assets consist of gathering systems and compression facilities, water handling and treatment facilities, and interests in processing and fractionation plants, through which Antero Midstream Partners and its affiliates, provides midstream services to us under long-term, fixed-fee contracts.

Sources of Our 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 2019, our production revenues were comprised of approximately 62% from the sale of natural gas and 38% 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.

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 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.

Until March 12, 2019, substantially all revenues from our gathering and processing and water handling and treatment operations were derived from our ownership and consolidation of Antero Midstream Partners.

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, treatment and 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 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 excess capacity we have 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 since 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. We did not record any costs related to exploratory dry holes during the years ended December 31, 2018 and 2019.

- *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 whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. We did not record any impairments for proved properties during the year ended December 31, 2018. 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 charge of $881 million related to proved properties in the Utica Shale during the year ended December 31, 2019.

- *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 9 to the consolidated financial statements for more information on our general and administrative expense.

- *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. At December 31, 2019, we had a fixed interest rate of 5.375% on our 2021 notes having a principal balance of $953 million, a fixed interest rate of 5.125% on our 2022 notes having a principal balance of $923 million, a fixed interest rate of 5.625% on our 2023 notes having a principal balance of $750 million, and a fixed interest rate of 5.00% on our 2025 notes having a principal balance of $600 million.

- *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. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income primarily from derivatives, oil and gas properties, and NOL carryforwards. At December 31, 2019, we had U.S. federal and state NOL carryforwards of approximately $2.2 billion and $2.0 billion, respectively, some of which expire at various dates between 2032 and 2038 while others have no expiration date. We recorded valuation allowances for deferred tax assets at December 31, 2019 of approximately $47 million related to state loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or as estimates of future taxable income are reduced.

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) 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, the results of Antero Midstream Partners were included in our consolidated financial statements. Effective March 13, 2019, the results of Antero Midstream Partners are no longer consolidated in our results; however, our segment disclosures include the segments of our unconsolidated affiliates, due to their significance to our operations. See Note 3 to the consolidated financial statements for further discussion on the Transactions and Note 18 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, 2018 Compared to Year Ended December 31, 2019

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

	Exploration and production	Marketing	Midstream	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2018:					
Revenue and other:					
Natural gas sales	$ 2,287,939	—	—	—	2,287,939
Natural gas liquids sales	1,177,777	—	—	—	1,177,777
Oil sales	187,178	—	—	—	187,178
Commodity derivative fair value losses	(87,594)	—	—	—	(87,594)
Gathering, compression, and water handling and treatment	—	—	1,027,939	(1,006,595)	21,344
Marketing	—	458,901	—	—	458,901
Marketing derivative fair value gains	—	94,081	—	—	94,081
Gain on sale of assets	—	—	583	(583)	—
Other income (expense)	(87,472)	—	—	87,472	—
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
Production and ad valorem taxes	122,305	—	4,169	—	126,474
Marketing	—	686,055	—	—	686,055
Exploration	4,958	—	—	—	4,958
Impairment of oil and gas properties	549,437	—	—	—	549,437
Impairment of midstream assets	—	—	9,658	—	9,658
Accretion of asset retirement obligations	2,684	—	135	—	2,819
Depletion, depreciation, and amortization	841,645	—	130,820	—	972,465
General and administrative (excluding equity-based compensation)	131,964	—	40,556	(2,590)	169,930
Equity-based compensation	49,341	—	21,073	—	70,414
Change in fair value of contingent acquisition consideration	—	—	(93,019)	93,019	—
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

	Exploration and production	Marketing	Equity Method Investment in Antero Midstream Corporation	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, and 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, compression, processing, and transportation	2,257,099	—	41,013	(151,465)	2,146,647
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
Loss on sale of assets	951	—	—	—	951
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
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)

Exploration and Production Segment Results for the Year Ended December 31, 2018 Compared to the Year Ended December 31, 2019

The following table sets forth selected operating data of the exploration and production segment for the year ended December 31, 2018 compared to the year ended December 31, 2019:

	Year ended December 31, 2018	Year ended December 31, 2019	Amount of Increase (Decrease)	Percent Change
Production data:				
Natural gas (Bcf)	710	822	112	16 %
C2 Ethane (MBbl)	14,221	15,861	1,640	12 %
C3+ NGLs (MBbl)	28,913	39,445	10,532	36 %
Oil (MBbl)	3,265	3,632	367	11 %
Combined (Bcfe)	989	1,175	186	19 %
Daily combined production (MMcfe/d)	2,709	3,220	511	19 %
Average prices before effects of derivative settlements [1]:				
Natural gas (per Mcf) [2]	$ 3.22	$ 2.74	$ (0.48)	(15)%
C2 Ethane (per Bbl)	$ 12.14	$ 7.85	$ (4.29)	(35)%
C3+ NGLs (per Bbl)	$ 34.76	$ 27.75	$ (7.01)	(20)%
Oil (per Bbl)	$ 57.34	$ 48.88	$ (8.46)	(15)%
Weighted Average Combined (per Mcfe)	$ 3.69	$ 3.10	$ (0.59)	(16)%
Average realized prices after effects of derivative settlements [1]:				
Natural gas (per Mcf)	$ 3.65	$ 3.14	$ (0.51)	(14)%
C2 Ethane (per Bbl)	$ 12.14	$ 7.85	$ (4.29)	(35)%
C3+ NGLs (per Bbl)	$ 33.25	$ 27.41	$ (5.84)	(18)%
Oil (per Bbl)	$ 52.11	$ 50.92	$ (1.19)	(2)%
Weighted Average Combined (per Mcfe)	$ 3.94	$ 3.38	$ (0.56)	(14)%
Average costs (per Mcfe):				
Lease operating	$ 0.14	$ 0.13	$ (0.01)	(7)%
Gathering, compression, processing, and transportation	$ 1.81	$ 1.92	$ 0.11	6 %
Production and ad valorem taxes	$ 0.12	$ 0.11	$ (0.01)	(8)%
Marketing expense (gain), net	$ 0.23	$ 0.22	$ (0.01)	(4)%
Depletion, depreciation, amortization, and accretion	$ 0.85	$ 0.76	$ (0.09)	(11)%
General and administrative (excluding equity-based compensation)	$ 0.13	$ 0.12	$ (0.01)	(8)%

(1) Average sales prices shown in the table reflect both 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 derivative monetizations), 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.

(2) The average realized price for 2019 includes $54 million of the proceeds related to the South Jersey Litigation. See Note 15 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 remained relatively constant with a decrease of $41 million over the prior year, or 2%. Increased natural gas production volumes accounted for an approximate $358 million increase in year-over-year natural gas sales (calculated as the change in year-to-year volumes times the prior year average price), and decreases in our prices, excluding the effects of derivative settlements, accounted for an approximate $399 million decrease in year-over-year gas sales revenue (calculated as the change in the year-to-year average price times current year production volumes).

NGLs sales. Revenues from sales of NGLs increased $41 million, or 4%. An increase in NGLs production volumes accounted for an approximate $386 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 $345 million decrease in year-over-year product 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 $187 million for the year ended December 31, 2018 to $178 million for the year ended December 31, 2019, a decrease of $10 million, or 5% due to increases in production offset by a decrease in prices.

During the year ended December 31, 2019, our natural gas prices and revenues included proceeds of $54 million from South Jersey Gas Company and South Jersey Resources Group, LLC (collectively, "SJGC") in the South Jersey Litigation resulting from resolution of contractual issues. These disputes with SJGC negatively affected our natural gas prices and revenues for prior periods including the year ended December 31, 2018. Please see Note 15 to the consolidated financial statements for more information on the South Jersey Litigation.

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, 2018 and 2019, our commodity hedges resulted in derivative fair value losses of $88 million and derivative fair value gains of $464 million, respectively. The commodity derivative fair value gains (losses) included $243 million and $325 million of cash proceeds on gains on settled derivatives for the years ended December 31, 2018 and 2019, respectively. Commodity derivative fair value gains (losses) for the years ended December 31, 2018 also include cash proceeds of $370 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.

Lease operating expense. Lease operating expense for the exploration and production segment increased from $142 million for the year ended December 31, 2018 to $147 million for the year ended December 31, 2019, an increase of 7%. This increase is primarily due to a 19% increase in production. On a per unit basis, lease operating expenses decreased from $0.14 per Mcfe for the year ended December 31, 2018 to $0.13 per Mcfe for the year ended December 31, 2019. The decrease in lease operating expenses on a per Mcfe basis is primarily due to decreased water disposal costs resulting from improved operating efficiencies and cost reductions.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $1.8 billion for the year ended December 31, 2018 to $2.3 billion for the year ended December 31, 2019. This is primarily a result of the 19% increase in production. On a per Mcfe basis, total gathering, compression, processing, and transportation expenses increased from $1.81 per Mcfe for the year ended December 31, 2018 to $1.92 per Mcfe for the year ended December 31, 2019. This per Mcfe increase was primarily the result of higher processing and transportation costs as NGLs production made up a higher percentage of our overall production and the Mariner East 2 NGL pipeline went into service in January 2019.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $122 million for the year ended December 31, 2018 to $124 million for the year ended December 31, 2019 primarily as a result of an increase in production revenues. On a per Mcfe basis, production and ad valorem taxes decreased from $0.12 per Mcfe for the year ended December 31, 2018 to $0.11 per Mcfe for the year ended December 31, 2019. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues remained relatively constant at approximately 3.4% for the years ended December 31, 2018 and 2019.

Exploration expense. Exploration expense representing expenses incurred for unsuccessful lease acquisition efforts decreased from $5 million for the year ended December 31, 2018 to $1 million for the year ended December 31, 2019 as leasing activities declined.

Impairment of oil and gas properties. Impairment of oil and gas properties increased from $549 million for the year ended December 31, 2018 to $1.3 billion for the year ended December 31, 2019 primarily due to impairment of proved properties in the Ohio Utica Shale. 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 evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount 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. The carrying amount of the Utica Shale exceeded the estimated undiscounted future cash flows based on future strip commodity prices at September 30, 2019. We estimated the fair value of the Utica Shale assets based on sales of other properties. As a result, the Company recorded an impairment charge of $881 million related to proved properties in the Utica Shale during the year ended December 31, 2019.

Depletion, depreciation, and amortization expense. DD&A expense increased from $842 million for the year ended December 31, 2018 to $893 million for the year ended December 31, 2019 for the exploration and production segment, primarily due to an increase in production and the related depletion associated with that production. DD&A per Mcfe decreased from $0.85 per Mcfe during the year ended December 31, 2018 to $0.76 per Mcfe during the year ended December 31, 2019 due to a reduction in the cost basis of producing properties as a result of the impairments discussed above.

General and administrative expense. General and administrative expense (excluding equity-based compensation expense) increased from $132 million for the year ended December 31, 2018 to $139 million for the year ended December 31, 2019, primarily due to increases in legal and other expenses related to the Transactions. On a per unit basis, general and administrative expense excluding equity-based compensation decreased by 8%, from $0.13 per Mcfe during the year ended December 31, 2018 to $0.12 per Mcfe during the year ended December 31, 2019 as the increase in expenses from 2018 to 2019 was offset by a 19% increase in production. We had 623 employees as of December 31, 2018 and 547 employees as of December 31, 2019.

Equity-based compensation expense. Noncash equity-based compensation expense decreased from $49 million for the year ended December 31, 2018 to $21 million for the year ended December 31, 2019 as a result of equity award forfeitures, non-recognition of performance share unit expense, and a large vesting of shares with higher fair values during 2018 resulting in lower expense going forward. When an equity award is forfeited, expense previously recognized for the award is reversed. See Note 9 to the consolidated financial statements for more information on equity-based compensation awards.

Marketing Segment Results for the Year Ended December 31, 2018 Compared to the Year Ended December 31, 2019

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.

Marketing revenues were $553 million and $292 million and expenses were $686 million and $550 million for the years ended December 31, 2018 and 2019, respectively, related to these activities.

Marketing expenses include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This includes firm transportation costs of $171 million and $252 million for the year ended December 31, 2018 and 2019, respectively, which increased primarily due to costs associated with the Rockies Express Pipeline that delivers natural gas to the Chicago and Michigan markets. Additionally, the marketing segment recorded a fair value gain of $94 million for the year ended December 31, 2018 related to several natural gas purchase and sales contracts that were determined to be derivative instruments. See Note 11 to the consolidated financial statements for more information on these marketing derivative fair value gains.

Operating losses on our marketing activities were $227 million (excluding the derivative fair value gains), or $0.23 per Mcfe, and $258 million, or $0.22 per Mcfe, for the years ended December 31, 2018 and 2019, respectively.

Based on current projected 2020 annual production guidance, we estimate that we could incur annual net marketing costs of $0.10 per Mcfe to $0.12 per Mcfe in 2020 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 spreads net of variable transportation costs. Our net marketing expense is expected to decrease in years subsequent to 2020 depending on our utilization of our transportation capacity, which will be affected by our future production and how much, if any, future excess transportation can be marketed to third parties. Our production outlook beyond 2020 assumes production growth and higher utilization of our transportation capacity.

Antero Midstream Corporation Segment Results for the Year Ended December 31, 2018 Compared to the Year Ended December 31, 2019

Throughout 2018 and during the period from January 1, 2019 through March 12, 2019, the results of Antero Midstream Partners were included in our consolidated financial statements. Effective March 13, 2019, the results of Antero Midstream Partners were no longer consolidated in our results. See Note 3 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 decreased from $1.0 billion for the year ended December 31, 2018, to $793 million, which included amortization of customer relationships of $57 million, for the year ended December 31, 2019, a decrease of $236 million, or 23%. The decrease in operating revenue was primarily due to a decrease in fresh water deliveries, which was partially offset by an increase in other fluid handling services for the year ended December 31, 2019. Total operating expenses related to the segment increased from $426 million for the year ended December 31, 2018 to $1.2 billion for the year ended December 31, 2019. The increase was primarily due impairments of $463 million on Antero Midstream's wastewater treatment facility, related goodwill and customer relationships, and $298 million related to the water handling segment goodwill as a result of the annual impairment test.

In addition, Antero Midstream Partners had equity in earnings of unconsolidated affiliates of $40 million and $51 million for the years ended December 31, 2018 and 2019, respectively.

Discussion of Items Not Allocated to Segments for the Year Ended December 31, 2018 Compared to the Year Ended December 31, 2019

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 delivers 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.

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

Interest expense. Interest expense decreased from $287 million for the year ended December 31, 2018 to $228 million for the year ended December 31, 2019 due to decreased interest rates on Credit Facility borrowings and decreased borrowings outstanding during 2019. Interest expense includes approximately $13 million and $11 million of non-cash amortization of deferred financing costs for the years ended December 31, 2018 and 2019, respectively.

Income tax benefit. Income tax benefit decreased from $129 million for the year ended December 31, 2018 to $74 million for the year ended December 31, 2019, primarily due to the reduction in noncontrolling interest and the impact on deferred tax of changes in our blended statutory rate. For the year ended December 31, 2019, our overall effective tax rate was different than the statutory rate of 21% primarily due to the effects of noncontrolling interest and state taxes. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for information regarding our income tax provision for the years ended December 31, 2018 and 2019.

At December 31, 2018 and December 31, 2019, we had U.S. federal and state NOL carryforwards of approximately $2.2 billion and $2.0, respectively. Many of these NOLs expire at various dates between 2032 and 2038 while others have no expiration date. Future interpretations relating to the passage of the Tax Cuts and Jobs Act that vary from our current interpretation, and possible changes to state tax laws in response to the recently enacted federal legislation, 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, 2017 Compared to Year Ended December 31, 2018

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, 2018 for a discussion of the results of operations for the year ended December 31, 2017 compared to the year ended December 31, 2018.

Capital Resources and Liquidity

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, and distributions/dividends from unconsolidated affiliates. Our primary use of cash has been for the exploration, development, and acquisition of oil and natural gas properties. As we pursue the development of 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.

As of December 31, 2019, we had 2,385 potential horizontal well locations in our proved, probable, and possible reserve base, which will take many years to develop. More specifically, our proved undeveloped reserves will require an estimated $2.6 billion of development capital over the next five years in order to fully develop the properties associated with our proved reserves.

Based on strip prices as of December 31, 2019, we believe that cash flows from operations will be sufficient to finance such future development costs. For a discussion of the risks related to development of 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."

In addition, we may from time to time repurchase shares of our common stock under our share repurchase program. Under our share repurchase program, we repurchased and retired 13,390,617 common shares for $39 million during the year ended December 31, 2019. We may also seek to retire or purchase our outstanding debt securities from time to time through cash purchases, 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.

During the fourth quarter of 2019, we repurchased $225 million principal amount of debt at a 17% weighted average discount, including a portion of our 5.375% senior notes due November 1, 2021 and our 5.125% senior notes due December 1, 2022. We recognized a gain of approximately $36 million on the early extinguishment of the debt repurchased.

The Credit Facility has a borrowing base of $4.5 billion and current lender commitments of $2.64 billion. The borrowing base is redetermined 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 2020. 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 as 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, NGLs, or oil. 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.

For the year ended December 31, 2019, our total consolidated capital expenditures were approximately $1.4 billion, including drilling and completion expenditures of $1.3 billion, leasehold additions of $89 million, gathering and compression expenditures of $48 million, water handling and treatment expenditures of $24 million, and other capital expenditures of $7 million. Our capital budget for 2020 is $1.2 billion. Our budget includes: $1.15 billion for drilling and completion and $50 million for leasehold expenditures. We do not budget for acquisitions. During 2020, we plan to operate an average of four drilling rigs and three to four completion crews and we plan to complete 120 to 130 horizontal wells in the Marcellus and Utica Shales in 2020. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Furthermore, in December 2019, we announced an asset sale program pursuant to which we expect to execute between $750 million and $1.0 billion asset monetization opportunities through 2020, which can include hedge restructuring and dispositions of lease acreage, minerals, producing properties or our shares of Antero Midstream common stock. We expect to use the proceeds from this program to reduce indebtedness. We initiated this program by selling $100 million of our shares of Antero Midstream common stock in December 2019.

Based on strip prices as of December 31, 2019, we believe that funds from operating cash flows, available borrowings under the Credit Facility, capital market transactions, distributions/dividends from unconsolidated affiliates and proceeds from our asset sale program 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, 2017, 2018 and 2019:

(in thousands)	Year Ended December 31, 2017	2018	2019
Net cash provided by operating activities	$ 2,006,291	$ 2,081,987	1,103,458
Net cash used in investing activities	(2,461,630)	(2,350,724)	(1,041,490)
Net cash provided by financing activities	452,170	240,296	557,564
Effect of deconsolidation of Antero Midstream Partners LP	—	—	(619,532)
Net decrease in cash and cash equivalents	$ (3,169)	$ (28,441)	—

Our consolidated cash flow statements for the years ended December 31, 2017, 2018 and 2019 includes 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, 2017, 2018 and 2019 are not representative of our expected future cash flows. See Note 3 to the consolidated financial statements for more information.

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

Cash Flows Provided by Operating Activities

Net cash provided by operating activities was $2.1 billion and $1.1 billion for the years ended December 31, 2018 and 2019, respectively. Cash flow from operations decreased from 2018 to 2019 primarily due to an increase in gathering, compression, processing, and transportation costs due to the deconsolidation of Antero Midstream Partners and a $370 million decrease in proceeds from derivative monetizations and settlements of as compared to the prior period.

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, and other variables influence the market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Cash Flows Used in Investing Activities

Cash flows used in investing activities decreased from $2.4 billion for the year ended December 31, 2018 to $1.0 billion for the year ended December 31, 2019, primarily due to a decrease in capital expenditures of $788 million during the year ended December 31, 2019 as compared to the same period in 2018, and $297 million in proceeds received in connection with the Transactions in the year ended December 31, 2019. See Note 3 to the consolidated financial statements for further discussion on the Transactions.

In addition, cash flows in investing activities included expenditures of Antero Midstream Partners related to construction of midstream and water handling and treatment infrastructure and investments in joint ventures through March 12, 2019. Effective March 13, 2019, these expenditures are no longer consolidated in our results. Excluding Antero Midstream Partners, capital expenditures were $1.7 billion and $1.3 billion for the years ended December 31, 2018 and 2019, respectively.

Total capital expenditures for oil and gas properties decreased from $1.5 billion during the year ended December 31, 2018 to $1.2 billion during the year ended December 31, 2019 due to a decrease in drilling and completion activity, increased efficiency and cost reductions. Capital expenditures for water handling and treatment systems decreased $73 million from $98 million for the year ended December 31, 2018 to $24 million for the year ended December 31, 2019, and capital expenditures for gathering and compression systems decreased $396 million from $444 million to $48 million for the year ended December 31, 2019. The decreases in capital expenditures for both the water handling and treatment systems, and the gathering and compression systems are due to the year ended December 31, 2019 only including Antero Midstream Partners' activity through the deconsolidation date of March 12, 2019 as compared to the year ended December 31, 2018 including Antero Midstream Partners' activity for the entire period. Additionally, investments in joint ventures by Antero Midstream Partners decreased $111 million from $136 million during the year ended December 31, 2018 to $25 million during the year ended December 31, 2019 due to the deconsolidation as of March 12, 2019.

Our consolidated exploration and production capital budget for 2020 is $1.2 billion. 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 to levels that do not generate an acceptable level of corporate returns, or costs increase to levels that do not generate an acceptable level of corporate returns, we could choose to 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. We routinely monitor and adjust our capital expenditures in response to changes in commodity prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows, and other factors both within and outside our control.

Cash Flows Provided by Financing Activities

During the years ended December 31, 2018 and 2019, net cash flows provided by financing activities were $240 million, and $558 million, respectively. The increase of $318 million was primarily as a result of capital market transactions and changes in long term debt including an issuance of senior notes of $650 million partially offset by a repayment of senior notes of $191 million.

In addition, under the share repurchase program launched in the fourth quarter of 2018, Antero repurchased and retired 9,144,796 common shares for $129 million during the year ended December 31, 2018 and 13,390,617 common shares for $39 million during the year ended December 31, 2019.

Net borrowings on the Credit Facility decreased from $660 million for the year ended December 31, 2018 to $232 million for the year ended December 31, 2019, primarily due to the additional funding provided by the issuance of senior notes described above.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2018

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, 2018 for a discussion of the cash flows for the year ended December 31, 2017 compared to the year ended December 31, 2018.

Debt Agreements and Contractual Obligations

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 annual redeterminations. At December 31, 2019, the borrowing base was $4.5 billion and lender commitments were $2.64 billion. The next redetermination of the borrowing base is scheduled to occur by the end of April 2020. At 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. At December 31, 2018, we had $405 million of borrowings and $685 million of letters of credit outstanding under the Credit Facility, with a weighted average interest rate of 3.95%. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the earliest stated redemption date of any series of Antero's senior notes, then outstanding.

Under the Credit Facility, "Investment Grade Period" is a period that, as long as no event of default has occurred, commences when Antero elects to give notice to the Administrative Agent that Antero has received at least one of either (i) a BBB- or better rating from Standard & Poor's or (ii) a Baa3 or better rating from Moody's (an "Investment Grade Rating"). An Investment Grade Period can end at Antero's election.

During any period that is not an Investment Grade Period, the Credit Facility is ratably secured by mortgages on substantially all of Antero's properties and guarantees from Antero's restricted subsidiaries, as applicable. During an Investment Grade Period, the liens securing the obligations under the Credit Facility shall be automatically released (subject to the provisions of the Credit Facility). The Credit Facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate, determined by Antero's election at the time of borrowing. During an Investment Grade Period, the margin applicable to the Credit Facility borrowings is determined with reference to Antero's credit rating and ranges from 0.125% to 0.50% lower than rates during a period that is not an Investment Grade Period, depending on Antero's credit rating and utilization under the Credit Facility. During any period that is not an Investment Grade Period, the margin applicable to the Credit Facility borrowings is determined with reference to utilization under the Credit Facility. For information concerning the effect of changes in interest rates on interest payments under these facilities, see "Item 7A. Quantitative and Qualitative Disclosure About Market Risk."

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.

During any period that is not an Investment Grade Period, the Credit Facility requires Antero and its restricted subsidiaries to maintain the following two financial ratios as of the end of each fiscal quarter:

- a current ratio, which is the ratio of our current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our current liabilities (excluding derivative liabilities), of not less than 1.0 to 1.0; and
- an interest coverage ratio, which is the ratio of EBITDAX (as defined by the credit facility agreement) to interest expense over the most recent four quarters, of not less than 2.5 to 1.0.

During an Investment Grade Period, the Credit Facility requires Antero and its restricted subsidiaries to maintain the following three financial ratios as of the end of each fiscal quarter:

- a current ratio, which is the ratio of our current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our current liabilities (excluding derivative liabilities), of not less than 1.0 to 1.0;
- a ratio of total Indebtedness (as defined by the credit facility agreement) to EBITDAX (as defined by the credit facility agreement) of not more than 4.25 to 1.00; and
- a ratio of PV-9 reflected in the most recently delivered reserve report to its total Indebtedness of not less than 1.50 to 1.00, but only if Antero does not have both (i) an unsecured rating from Moody's of Baa3 or better and (ii) an unsecured rating from S&P of BBB- or better.

We were in compliance with the applicable covenants and ratios as of December 31, 2018 and December 31, 2019. The actual borrowing capacity available to us may be limited by the financial ratio covenants. At December 31, 2019, our current ratio was 5.25 to 1.0 (based on the $4.5 billion borrowing base under the Credit Facility) and our interest coverage ratio was 5.95 to 1.0.

Antero Resources Senior Notes. On November 5, 2013, We issued the 2021 notes at par. The 2021 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2021 notes rank pari passu to our other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by our wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. We may redeem all or part of the 2021 notes at any time at a redemption price of 100.00%. If we undergo a change of control followed by a rating decline, the holders of the 2021 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2021 notes, plus accrued and unpaid interest.

On May 6, 2014, we issued the 2022 notes at par. On September 18, 2014, we 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 our other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by our 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. We may redeem all or part of the 2022 notes at any time at redemption prices ranging from 101.281% currently to 100.00% on or after June 1, 2020. If we undergo a change of control followed by a rating decline, the holders of the 2022 notes will have the right to require us 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.

On March 17, 2015, we 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 our other outstanding senior notes. The 2023 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by our 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. We may redeem all or part of the 2023 notes at any time at redemption prices ranging from 102.813% to 100.00% on or after June 1, 2021. If we undergo a change of control followed by a rating decline, the holders of the 2023 notes will have the right to require us 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.

On December 21, 2016, we 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 our 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. We 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, we 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, we 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 we undergo a change of control following a ratings decline, the holders of the 2025 notes will have the right to require us 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.

We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under the Credit Facility, redeem previously issued senior notes, and for development of our oil and natural gas properties.

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, 2018 and 2019.

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. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, and other factors. The amounts involved could be material. During the fourth quarter of 2019, we repurchased $225 million principal amount of debt at a 17% weighted average discount, including a portion of our 2021 notes and our 2022 notes. The Company recognized a gain of approximately $36 million on the early extinguishment of the debt repurchased.

Treasury Management Facility. We have a revolving note with a lender that provides for up to $25 million of cash management obligations in order to facilitate our daily treasury management. Borrowings under the revolving note are secured by the collateral for the Credit Facility. Borrowings under the revolving note bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2020. At December 31, 2018, there was $5.4 million included in "Other current liabilities" on the Company's Consolidated Balance Sheet, and at December 31, 2019, there were no outstanding borrowings under this revolving note.

Contractual Obligations. A summary of our contractual obligations as of December 31, 2019 is provided in the table below. 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)	2020	2021	2022	2023	2024	Thereafter	Total
Recorded contractual obligations:							
Credit Facility (1)	$ —	552	—	—	—	—	552
Antero senior notes—principal (2)	—	953	923	750	—	600	3,226
Antero senior notes—interest (2)	171	145	119	51	30	30	546
Operating leases (3)	304	265	284	314	342	1,378	2,887
Finance leases (3)	—	1	1	—	—	—	2
Imputed interest for leases (3)	318	289	259	225	188	474	1,753
Asset retirement obligations (4)	—	—	—	—	—	55	55
Unrecorded contractual obligations:							
Firm transportation (5)	1,105	1,077	1,034	1,057	1,017	7,907	13,197
Processing, gathering, and compression services (6)	55	54	54	59	59	153	434
Drilling and completion	30	—	—	—	—	—	30
Land payment obligations (7)	5	3	—	—	—	—	8
Total	$ 1,988	3,339	2,674	2,456	1,636	10,597	22,690

(1) Includes outstanding principal amounts at December 31, 2019. 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 maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the earliest stated redemption of any series of our senior notes then outstanding.

(2) Our senior notes include the 2021 notes, the 2022 notes, the 2023 notes, and the 2025 notes.

(3) Includes contracts for services provided by drilling rigs and completion fleets, processing, gathering and compression services agreements, and office and equipment leases that expire at various dates from January 2020 through November 2021. 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 12 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. This includes fees to be paid to the Joint Venture owned by Antero Midstream and MarkWest. 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. 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 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, 2017, 2018 and 2019. 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 $160 million, $549 million, and $393 million for the years ended December 31, 2017, 2018 and 2019, 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. If such revisions are significant, they could significantly affect the future amortization rates of capitalized costs and result in asset impairments that may be material.

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, 2017 and 2018. 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 oil and gas properties of $881 million related to proved 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 3.25% per from future pricing levels at December 31, 2019, 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 3.25% from year-end 2019 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 Financial Accounting Standards Board (the "FASB") Accounting Standards Codification 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 an unconsolidated 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 9 to the consolidated financial statements for further discussion on our equity method investments.

At December 31, 2019 we determined that events and circumstances indicated that the carrying value had experienced an other-than-temporary decline and we recorded an impairment of $468 million. The fair value of the equity method investment in Antero Midstream was based on the quoted market common stock price of Antero Midstream at 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 the utilization of NOL carryforwards. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income, primarily from derivatives, oil and gas properties, and net operating loss carryforwards. We have generated net operating loss carryforwards, some of which expire at various dates from 2032 to 2038 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, 2019, we have recognized a valuation allowance of $47 million for net operating loss carryforwards 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

In August 2018, the FASB issued ASU No. 2018-13, “Fair Value Measurement: Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurement,” which provides changes to certain fair value disclosure requirements. This ASU is effective for annual reporting periods beginning after December 15, 2019 and interim periods within those annual periods, with early adoption permitted. The adoption of this update is not expected to have a material impact on our consolidated financial statements.

Off-Balance Sheet Arrangements

As of December 31, 2019, 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. At December 31, 2019, our commodity derivatives included fixed price swaps and basis differential swaps at index-based pricing.

At December 31, 2019, we had in place natural gas swaps covering portions of our projected production through 2024. Our commodity hedge position as of December 31, 2019 is summarized in Note 11 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K. 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, 2019, our revenues would have decreased by approximately $64 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 at December 31, 2019.

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. At 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 liabilities. At December 31, 2018, the estimated fair value of our commodity derivative instruments was a net asset of $607 million, comprised of current and noncurrent assets and current liabilities.

By removing price volatility from a portion of our expected production through December 2024, 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 ($746 million at December 31, 2019) and the sale of our natural gas, NGLs, and oil production ($297 million at December 31, 2019) 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 $746 million at December 31, 2019 included the following derivative assets by bank counterparty: Wells Fargo - $215 million; JP Morgan - $134 million; Morgan Stanley - $121 million; Citigroup - $117 million; Scotiabank - $58 million; Canadian Imperial Bank of Commerce - $44 million; PNC - $29 million; BNP Paribas - $21 million; Natixis - $10 million; and SunTrust $7 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) at December 31, 2019 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, 2019, 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, 2019 was approximately 4.16%. We estimate that a 1.0% increase in the applicable average interest rates for the year ended December 31, 2019 would have resulted in an estimated $2.6 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, 2019 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, 2019 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, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019 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, 2019, 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 2020 Annual Meeting of Stockholders.

Directors and Executive Officers

The following table sets forth names, ages and titles of our directors and executive officers as of February 12, 2020:

Name	Age	Title
Paul M. Rady	66	Chairman of the Board, Director and Chief Executive Officer
Glen C. Warren, Jr.	64	President, Director, Chief Financial Officer and Secretary
W. Patrick Ash	41	Senior Vice President— Reserves, Planning and Midstream
Michael N. Kennedy	45	Senior Vice President—Finance
Alvyn A. Schopp	61	Chief Administrative Officer and Regional Senior Vice President
Robert J. Clark	75	Director
Benjamin A. Hardesty	70	Director
W. Howard Keenan Jr.	69	Director
Paul J. Korus	63	Director
Joyce E. McConnell	65	Director
Vicky Sutil	55	Director
Thomas B. Tyree, Jr.	59	Director

Set forth below is the description of the backgrounds of our directors and executive officers.

Paul M. Rady has served as our Chief Executive Officer and Chairman of the Board of Directors since May 2004, and he served in the same roles of our predecessor company from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Mr. Rady has also served as Chief Executive Officer and Chairman of the Board of Directors of Antero Midstream since March 2019, and previously in the same positions at the general partner of Antero Midstream Partners from February 2014 through March 2019 of the general partner of AMGP from April 2017 through March 2019. Prior to Antero, Mr. Rady served as President, CEO and Chairman of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Prior to Pennaco, Mr. Rady was with Barrett Resources from 1990 until 1998 where he initially was recruited as Chief Geologist in 1990, then served as Exploration Manager, EVP Exploration, President, COO and Director and ultimately CEO. Mr. Rady began his career with Amoco where he served 10 years as a geologist focused on the Rockies and Mid-Continent. Mr. Rady is the managing member of Salisbury Investment Holdings, LLC. Mr. Rady holds a B.A. in Geology from Western Colorado University and M.Sc. in Geology from Western Washington University.

Mr. Rady's significant experience as a chief executive of oil and gas companies, together with his training as a geologist and broad industry knowledge, enable Mr. Rady to provide the board with executive counsel on a full range of business, strategic and professional matters.

Glen C. Warren, Jr. has served as our President, Chief Financial Officer and Secretary and as a director since May 2004, and as President and Chief Financial Officer and as a director of our predecessor company from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Mr. Warren has also served as President and Secretary and as a director of the Board of Directors of Antero Midstream since March 2019, and previously in the same positions at the general partner of Antero Midstream Partners from February 2014 through March 2019 and of the general partner of AMGP from April 2017 through March 2019. Prior to Antero, Mr. Warren served as EVP, CFO and Director of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Mr. Warren spent 10 years as a natural resources investment banker focused on equity and debt financing and M&A advisory with Lehman Brothers, Dillon Read and Kidder Peabody. Mr. Warren began his career as a landman in the Gulf Coast region with Amoco, where he spent six years. Mr. Warren is the managing member of Canton Investment Holdings, LLC. Mr. Warren holds a B.A. from the University of Mississippi, a J.D. from the University of Mississippi School of Law and an M.B.A. from the Anderson School of Management at U.C.L.A.

Mr. Warren's significant experience as a chief financial officer of oil and gas companies, together with his experience as an investment banker and broad industry knowledge, enable Mr. Warren to provide the board with executive counsel on a full range of business, strategic, financial and professional matters.

W. Patrick Ash has served as our and Antero Midstream's Senior Vice President - Reserves, Planning and Midstream since June

2019, prior to which he served as our Vice President of Reservoir Engineering and Planning beginning in December 2017 and the same at Antero Midstream beginning with the closing of the Transactions in March 2019. Prior to the Transactions, Mr. Ash served as AMGP's and Antero Midstream Partners' Vice President of Reservoir Engineering and Planning beginning in December 2017. Prior to joining us, Mr. Ash was at Ultra Petroleum for six years in management positions of increasing responsibility, most recently serving as Vice President, Development, including during and after Ultra's bankruptcy proceedings, from which it emerged in 2017. 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, NFR Energy and Encana. Mr. Ash holds a B.S. in Petroleum Engineering from Texas A&M University and a MBA from Washington University in St. Louis.

Michael N. Kennedy has served as our Senior Vice President of Finance and Chief Financial Officer since January 2016, prior to which he served as our Vice President of Finance beginning in August 2013. Mr. Kennedy has also served as Antero Midstream's Chief Financial Officer and Senior Vice President of Finance since March 2019 and previously served as Chief Financial Officer of Antero Midstream Partners from January 2016, prior to which he served as Vice President of Finance of Antero Midstream Partners beginning in February 2014, as well as the Chief Financial Officer and Senior Vice President of Finance of AMGP from April 2017. Mr. Kennedy was Executive Vice President and Chief Financial Officer of Forest Oil Corporation 2009 to 2013. From 2001 until 2009, Mr. Kennedy held various financial positions of increasing responsibility within Forest. From 1996 to 2001, Mr. Kennedy was an auditor with Arthur Andersen LLP focusing on the Natural Resources industry. Mr. Kennedy holds a B.S. in Accounting from the University of Colorado at Boulder.

Alvyn A. Schopp has served as our Chief Administrative Officer and Senior Regional Vice President since January 2020, as Chief Administrative Officer, Regional Senior Vice President and Treasurer from January 2016 to December 2019, as Chief Administrative Officer, Regional Vice President and Treasurer from October 2013 to January 2016, as Vice President of Accounting and Administration and Treasurer from January 2005 to September 2013, as Controller and Treasurer from 2003 to 2005 and as our predecessor company's Vice President of Accounting and Administration and Treasurer from January 2005 until its sale to XTO Energy, Inc. in 2005. Mr. Schopp has also served as Chief Administrative Officer and Senior Regional Vice President of Antero Midstream since January 2020, prior to which he served as Chief Administrative Officer, Regional Senior Vice President and Treasurer of Antero Midstream beginning in March 2019. Mr. Schopp also served as Chief Administrative Officer, Regional Senior Vice President and Treasurer of AMGP from April 2017 to March 2019, as well as Chief Administrative Officer, Regional Senior Vice President and Treasurer of Antero Midstream Partners from February 2014 to March 2019. From 2002 to 2003, Mr. Schopp was an Executive Financial Consultant with Duke Energy Field Services. From 1993 to 2000, Mr. Schopp was CFO, Director and ultimately CEO of T-Netix. From 1980 to 1993, Mr. Schopp was with KPMG LLP. As a Senior Manager with KPMG, he maintained an extensive energy and mining practice. Mr. Schopp holds a B.B.A. from Drake University.

Robert J. Clark has served as a director since October 2013. He is Chairman of our Compensation Committee and currently serves as a member of our Nominating & Governance Committee. Mr. Clark has been Chairman of 3 Bear Energy, LLC, a midstream energy company with operations in the Rocky Mountains, since its formation in March 2013, and served as its Chief Executive Officer from March 2013 until 2019. Prior to the formation of 3 Bear Energy LLC, Mr. Clark formed, operated and subsequently sold Bear Tracker Energy in February 2013 (to Summit Midstream Partners, LP), a portion of Bear Cub Energy in April 2007 (to Regency Energy Partners, L.P.) and the remaining portion in December 2008 (to GeoPetro Resources Company) and Bear Paw Energy in 2001 (to ONEOK Partners, L.P., formerly Northern Border Partners, L.P.). Mr. Clark was President of SOCO Gas Systems, Inc. and Vice President-Gas Management for Snyder Oil Corporation from 1988 to 1995. Mr. Clark served as Vice President Gas-Gathering, Processing and Marketing of Ladd Petroleum Corporation, an affiliate of General Electric, from 1985 to 1988. Prior to 1985, Mr. Clark held various management positions with NICOR, Inc. Mr. Clark received his Bachelor of Science degree from Bradley University and his Master's Degree in Business Administration from Northern Illinois University. Mr. Clark is a member of the board of trustees of Children's Hospital Colorado Foundation and the board of directors of Judi's House, a Denver charity for grieving children and families and the Boys and Girls Club of Metro Denver.

Mr. Clark has significant experience with energy companies, with over 50 years of experience in the industry. We believe his background and skill set make Mr. Clark well-suited to serve as a member of our board of directors.

Benjamin A. Hardesty has served as a director since October 2013. He is Chairman of our Nominating & Governance Committee, and he currently serves as a member of our Compensation Committee and Audit Committee. Mr. Hardesty has been the owner of Alta Energy LLC, a consulting business focused on oil and natural gas in the Appalachian Basin and onshore United States, since May 2010. In May 2010, Mr. Hardesty retired as president of Dominion E&P, Inc., a subsidiary of Dominion Resources Inc. (NYSE: D) engaged in the exploration and production of natural gas in North America, a position he had held since September 2007. Mr. Hardesty joined Dominion in 1995 and served as president of Dominion Appalachian Development, Inc. until 2000 and general manager and vice president—Northeast Gas Basins until 2007. Mr. Hardesty was a member of the board of Directors of Blue Dot

Energy Services LLC from 2011 until its sale to B/E Aerospace in 2013. From 1982 to 1995, Mr. Hardesty served successively as vice president, executive vice president and president of Stonewall Gas Company, and from 1978 to 1982, he served as vice president-operations of Development Drilling Corp. Mr. Hardesty received his Bachelor of Science degree from West Virginia University and his Master of Science—Management degree from The George Washington University. Mr. Hardesty served as an active duty officer in the U.S. Army Security Agency. Mr. Hardesty currently serves on the board of directors of KLX Energy Services Inc. Mr. Hardesty is a director emeritus and past president of the West Virginia Oil & Natural Gas Association and past president of the Independent Oil & Gas Association of West Virginia. Additionally, Mr. Hardesty is a trustee and past chairman of the Nature Conservancy of West Virginia and a member of the board of directors of the West Virginia Chamber of Commerce. Mr. Hardesty serves as a member of the Visiting Committee of the Petroleum Natural Gas Engineering Department of the College of Engineering and Mineral Resources at West Virginia University.

Mr. Hardesty has significant experience in the oil and natural gas industry, including in our areas of operation. We believe his background and skill set make Mr. Hardesty well-suited to serve as a member of our board of directors.

W. Howard Keenan, Jr. has served as a director since 2004 and is a member of our Nominating & Governance Committee. He has also served on the Board of Directors of Antero Midstream since March 2019, and previously as a director at the general partner of Antero Midstream Partners beginning in February 2014, as well as the general partner of AMGP beginning in April 2017. Mr. Keenan has over 40 years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private investment manager focused on the energy industry. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas, including the founding of the first Yorktown Partners fund in 1991. He is serving or has served as a director of multiple Yorktown portfolio companies and currently serves as a director of the following public companies: Brigham Minerals, Inc. and Solaris Oilfield Infrastructure, Inc. Mr. Keenan holds an B.A. degree cum laude from Harvard College and an M.B.A. degree from Harvard University.

Mr. Keenan has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Keenan well-suited to serve as a member of our board of directors.

Paul J. Korus has served as a director since December 2018. He is Chairman of our Audit Committee and is a member of our Audit and Nominating & Governance Committees. Mr. Korus previously served on the Board of Directors and Audit Committee of the general partner of Antero Midstream Partners from January 2019 to March 2019. Mr. Korus was also appointed to the Board of Directors of SRC Energy Inc. in 2016, which was acquired by PDC Energy, Inc. in January 2020. In connection with such acquisition, Mr. Korus was appointed to serve on the Board of Directors of PDC Energy, Inc. In September 2015, Mr. Korus retired as senior vice president and Chief Financial Officer of Cimarex Energy Co., a position he had held since 1999. His responsibilities there included management of accounting, treasury, internal audit, investor relations, capital markets and financial planning and analysis. Between 1995 and 1999 he was an equity research analyst with Petrie Parkman & Co., a boutique energy investment banking firm that subsequently merged into Merrill Lynch. From 1982 to 1995 Mr. Korus was with Apache Corporation, where he held positions of increasing responsibility in management information systems, corporate planning and investor relations. Mr. Korus began his business career in 1980 with a large public accounting firm (Arthur Andersen) as a management information systems consultant. Mr. Korus previously served as Chairman of the University of North Dakota (UND) Business School Advisory Council. Paul graduated from UND with a Bachelor's of Science degree in Economics in 1978 and a Master's of Science degree in Accounting in 1980. He is currently a member of the National Association of Corporate Directors.

Mr. Korus has extensive knowledge of the energy industry as a former executive officer and current director of a public energy company, and he also has experience in technical accounting and auditing matters. We believe his background and skill set make Mr. Korus well suited to serve as a member of our board of directors.

Joyce E. McConnell has served as a director since February 2018 and is a member of our Nominating & Governance Committee. She has served as the President of Colorado State University since March 2019. She was previously Provost and Vice President for Academic Affairs at West Virginia University from 2014 to 2019, where she was responsible for the administration of all academic policies, programs, facilities and budgetary matters. From 2008 to 2014, she served as Dean of the West Virginia University College of Law, where she helped raise $36 million in capital campaign funds, expand multidisciplinary opportunities and develop experiential and clinical programs and facilities. As Dean, she also helped implement energy research initiatives including the Energy and Sustainable Development and Land Use Sustainability Clinic at the College of Law, West Virginia University's Energy Institute and the Energy finance emphasis in West Virginia University's College of Business & Economics. McConnell currently serves on the National Collegiate Athletic Association Division One Committee on Infractions and as Chair of the Board of Trustees of the Nature Conservancy in West Virginia. From 2016 to 2017, Ms. McConnell served as President of the West Virginia Bar Association. Ms. McConnell holds a B.A. from The Evergreen State College, a J.D. from Antioch School of Law and LL.M. from Georgetown University

Law Center.

Ms. McConnell's has broad legal and management experience and deep local ties to the West Virginia community in which the Company operates. We believe his background and skill set make Ms. McConnell well-suited to serve as a member of the board of directors.

Vicky Sutil has served as a director since October 2019 and is a member of our Compensation Committee and our Nominating & Governance Committee. Since 2017, Ms. Sutil has served as Strategic Planning Advisor to SK E&P Company, prior to which she served as Vice President of Commercial Analysis for CRC Marketing, Inc., an affiliate of California Resources Corporation, from 2014 to 2016. Prior to that, Ms. Sutil worked for Occidental Petroleum in a variety of corporate and asset level capacities, both upstream and midstream, from 2000 to 2014. She began her career serving in a number of project management and commercial roles across both the upstream and downstream businesses at ARCO and Mobil Oil between 1988 and 2000. Ms. Sutil served as Occidental's representative on the boards of the general partners of Plains All American Pipeline, L.P. and Plains GP Holdings, L.P. until 2015, and currently serves on the board and as a member of the audit committee of Delek U.S. Holdings. Ms. Sutil received a Bachelor of Science in Mechanical Engineering with a petroleum emphasis from the University of California at Berkeley and a Master of Business Administration degree from the Pepperdine University School of Business and Management.

Ms. Sutil has significant experience in the oil and natural gas industry. We believe her background and skill set make Ms. Sutil well-suited to serve as a member of our board of directors.

Thomas B. Tyree, Jr. has served as a director since October 2019 and is a member of our Audit Committee and our Compensation Committee. Mr. Tyree is currently the Chairman of Northwoods Energy LLC, an upstream oil and gas company that he founded in January 2018. Previously, Mr. Tyree was a co-founder and served as President, Chief Financial Officer and a Board member of Vantage Energy, LLC from 2006 until its sale to Rice Energy Inc. in October 2016. Prior to Vantage, he served as Chief Financial Officer of Bill Barrett Corporation from 2003 through 2006. Before transitioning to the oil and gas industry at Bill Barrett Corporation, Mr. Tyree was an investment banker at Goldman, Sachs & Co. from 1989 to 2003, focused on strategic advisory and financing transactions primarily with energy and industrial companies. Mr. Tyree currently serves on the board of Bonanza Creek Energy, an oil and gas company focused on the DJ Basin of Colorado. He received his Bachelor of Arts from Colgate University and currently serves as a member of the Colgate Board of Trustees. Mr. Tyree received a Master of Business Administration degree from the Wharton School at the University of Pennsylvania.

Mr. Tyree has significant experience in the oil and natural gas industry. We believe his background and skill set make Mr. Tyree well-suited to serve as a member of our board of directors.

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 2020 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 2020 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 2020 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 2020 Annual Meeting of Stockholders.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

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

(a)(3) Exhibits.

Exhibit Number	Description of Exhibit
2.1	Simplification Agreement, dated as of October 9, 2018, by and among AMGP GP LLC, Antero Midstream GP LP, Antero IDR Holdings LLC, Arkrose Midstream Preferred Co LLC, Arkrose Midstream NewCo Inc., Arkrose Midstream Merger Sub LLC, Antero Midstream Partners GP LLC and Antero Midstream Partners LP (incorporated by reference to Exhibit 2.1 to Antero Midstream GP LP’s Current Report on Form 8-K (Commission File No. 001-38075) filed on October 10, 2018).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	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 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance 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 November 7, 2013).
4.2	Form of 5.375% Senior Note due 2021 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
4.3	First Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.4	Second Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of March 18, 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 Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
4.5*	Third Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated November 24, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.6*	Fourth Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated January 21, 2015, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.7	Fifth Supplemental Indenture related to the 5.375% Senior Notes due 2021, 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 4.1 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.8	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).
4.9	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).
4.10	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).
4.11	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

Exhibit Number	Description of Exhibit
	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).
4.12	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).
4.13	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).
4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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.
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.
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.
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.
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).

Exhibit Number	Description of Exhibit
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 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.
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.
10.14†	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).
10.15†	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).
10.16†	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).
10.17†	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).
10.18†	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).
10.19†	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).
10.20†	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).
10.21	Voting Agreement, dated as of October 9, 2018, by and between Antero Midstream GP LP and Antero Resources Corporation (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).
10.22	Amendment No. 1 to the Voting Agreement by and between Antero Midstream GP LP and Antero Resources Corporation, dated as of March 11, 2019 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on March 13, 2019).
10.23	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).
10.24	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).
21.1*	Subsidiaries of Antero Resources Corporation.
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).

Exhibit Number	Description of Exhibit
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 21, 2020, for proved reserves as of December 31, 2019.
99.2	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).
99.3	Report of DeGolyer and MacNaughton, dated as of January 10, 2018, for proved reserves as of December 31, 2017 (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, 2018).
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, 2019, 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 12, 2020

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 12, 2020
/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr.	President, Director, Chief Financial Officer and Secretary (principal financial officer)	February 12, 2020
/s/ K. PHIL YOO K. Phil Yoo	Vice President, Accounting and Chief Accounting Officer (principal accounting officer)	February 12, 2020
/s/ ROBERT J. CLARK Robert J. Clark	Director	February 12, 2020
/s/ BENJAMIN A. HARDESTY Benjamin A. Hardesty	Director	February 12, 2020
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 12, 2020
/s/ PAUL J. KORUS Paul J. Korus	Director	February 12, 2020
/s/ JOYCE E. MCCONNELL Joyce E. McConnell	Director	February 12, 2020
/s/ VICKY SUTIL Vicky Sutil	Director	February 12, 2020
/s/ THOMAS B. TYREE, JR. Thomas B. Tyree, Jr.	Director	February 12, 2020

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Report of Independent Registered Public Accounting Firm

To the Stockholders and 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, 2018 and 2019, the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2019, 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, 2019, based on criteria established in *Internal Control – Integrated Framew*ork (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, 2018 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, 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, 2019 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 12 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 within *Item 9A. Controls and Procedures*. 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 Matters

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

Assessment of the adoption of ASC 842, Leases

As discussed in Note 12 to the consolidated financial statements, the Company adopted ASU 2016-02, Leases (Topic 842) on January 1, 2019. As a result of this adoption the Company recognized $3,437,685 thousand of right of use assets and liabilities on its balance sheet as of January 1, 2019.

We identified the assessment of the adoption of Topic 842, Leases as a critical audit matter. There was subjectivity and complexity in the determination of an appropriate method and model used to calculate the Company's incremental borrowing rates, which were used to discount the unpaid lease payments to present value.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's process over implementing the new accounting standard, including controls related to the determination of the Company's incremental borrowing rates. We involved valuation professionals with specialized skills and knowledge who assisted in:

- evaluating the methodology used by the Company to determine the incremental borrowing rates;
- comparing the assumptions used to determine the incremental borrowing rates to publicly available market data; and
- checking the Company's application of these assumptions to the calculation of its incremental borrowing rates.

Assessment of the impact of estimated oil and gas reserves on depletion expense related to proved oil and gas properties

As discussed in Note 1 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, 2019, the Company recorded depletion expense related to proved oil and gas properties of $884 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 assumptions used by the Company related to forecasted production, operating costs, and forecasted oil and gas prices inclusive of market differentials.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's depletion calculation process, and the estimation of proved oil and gas reserves, including controls related to selection of inputs to the reserves estimate. We evaluated the competence, capabilities, and objectivity of the internal reservoir engineers who estimated the proved oil and gas reserves and the external reservoir engineering specialists engaged by the Company. We analyzed and recalculated the 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.

Assessment of the fair value of proved and unproved oil and gas properties in the Utica Shale

As discussed in Note 1 to the consolidated financial statements, the Company determined that certain oil and gas properties were impaired and recorded impairment charges related to proved properties of $881 million and related to unproved properties of $393 million. Specifically, the Company estimated the fair value of its Utica Shale proved and unproved oil and gas properties based on sales of other comparable properties. For the Utica Shale proved oil and gas properties, the Company also adjusted the comparable properties for estimated future commodity prices to take into account changes in the commodity pricing environment.

We identified the assessment of the fair value of proved and unproved oil and gas properties in the Utica Shale as a critical audit matter. Complex auditor judgment was required in evaluating the Company's estimated fair value of proved and unproved oil and gas properties in the Utica Shale, specifically in evaluating the Company's valuation methodology as well as the comparable transactions selected by the Company for use in the calculation. Additionally, auditor judgment was required in evaluating the estimated future commodity pricing adjustments used by the Company to determine fair value of the Utica Shale proved oil and gas properties.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's process for determining the fair value of its Utica Shale proved and unproved oil and gas properties, including the methodology used, the comparable transactions selected and the pricing adjustments applied to comparable transactions for those proved oil and gas properties. We checked the pricing adjustments related to changes in the commodity pricing environment based on publicly available pricing information. We also evaluated the sales of other comparable proved and unproved oil and gas properties used in the valuation. We involved valuation professionals with specialized skills and knowledge to evaluate the methodology used by the Company, to evaluate the comparable transactions selected and to assess the pricing adjustments made to those comparable transactions for those proved oil and gas properties.

/s/ KPMG LLP

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

Denver, Colorado
February 12, 2020

ANTERO RESOURCES CORPORATION
Consolidated Balance Sheets
December 31, 2018 and 2019
(In thousands, except per share amounts)

		2018	2019
Assets			
Current assets:			
Accounts receivable	$	51,073	46,419
Accounts receivable, related parties		—	125,000
Accrued revenue		474,827	317,886
Derivative instruments		245,263	422,849
Other current assets		35,450	10,731
Total current assets		806,613	922,885
Property and equipment:			
Oil and gas properties, at cost (successful efforts method):			
Unproved properties		1,767,600	1,368,854
Proved properties		12,705,672	11,859,817
Water handling and treatment systems		1,013,818	—
Gathering systems and facilities		2,470,708	5,802
Other property and equipment		65,842	71,895
		18,023,640	13,306,368
Less accumulated depletion, depreciation, and amortization		(4,153,725)	(3,327,629)
Property and equipment, net		13,869,915	9,978,739
Operating leases right-of-use assets		—	2,886,500
Derivative instruments		362,169	333,174
Investments in unconsolidated affiliates		433,642	1,055,177
Other assets		47,125	21,094
Total assets	$	15,519,464	15,197,569
Liabilities and Equity			
Current liabilities:			
Accounts payable	$	66,289	14,498
Accounts payable, related parties		—	97,883
Accrued liabilities		465,070	400,850
Revenue distributions payable		310,827	207,988
Derivative instruments		532	6,721
Short-term lease liabilities		2,459	305,320
Other current liabilities		8,363	6,879
Total current liabilities		853,540	1,040,139
Long-term liabilities:			
Long-term debt		5,461,688	3,758,868
Deferred income tax liability		650,788	781,987
Derivative instruments		—	3,519
Long-term lease liabilities		2,873	2,583,678
Other liabilities		63,098	58,635
Total liabilities		7,031,987	8,226,826
Commitments and contingencies (Notes 14 and 15)			
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; 308,594 shares and 295,941 shares issued and outstanding at December 31, 2018 and 2019, respectively		3,086	2,959
Additional paid-in capital		6,485,174	6,130,365
Accumulated earnings		1,177,548	837,419
Total stockholders' equity		7,665,808	6,970,743
Noncontrolling interests in consolidated subsidiary		821,669	—
Total equity		8,487,477	6,970,743
Total liabilities and equity	$	15,519,464	15,197,569

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income (Loss)

Years Ended December 31, 2017, 2018 and 2019

(In thousands, except per share amounts)

	Year Ended December 31,		
	2017	2018	2019
Revenue and other:			
Natural gas sales	$ 1,769,284	2,287,939	2,247,162
Natural gas liquids sales	870,441	1,177,777	1,219,162
Oil sales	108,195	187,178	177,549
Commodity derivative fair value gains (losses)	658,283	(87,594)	463,972
Gathering, compression, water handling and treatment	12,720	21,344	4,478
Marketing	258,045	458,901	292,207
Marketing derivative fair value gains (losses)	(21,394)	94,081	—
Other income	—	—	4,160
Total revenue and other	3,655,574	4,139,626	4,408,690
Operating expenses:			
Lease operating	89,057	136,153	145,720
Gathering, compression, processing, and transportation	1,095,639	1,339,358	2,146,647
Production and ad valorem taxes	94,521	126,474	125,142
Marketing	366,281	686,055	549,814
Exploration	8,538	4,958	884
Impairment of oil and gas properties	159,598	549,437	1,300,444
Impairment of midstream assets	23,431	9,658	14,782
Depletion, depreciation, and amortization	824,610	972,465	914,867
Loss on sale of assets	—	—	951
Accretion of asset retirement obligations	2,610	2,819	3,762
General and administrative (including equity-based compensation expense of $103,445, $70,414 and $23,559 in 2017, 2018 and 2019, respectively)	251,196	240,344	178,696
Contract termination and rig stacking	—	—	14,026
Total operating expenses	2,915,481	4,067,721	5,395,735
Operating income (loss)	740,093	71,905	(987,045)
Other income (expenses):			
Water earnout	—	—	125,000
Equity in earnings (loss) of unconsolidated affiliates	20,194	40,280	(143,216)
Loss on the sale of equity investment shares	—	—	(108,745)
Impairment of equity investments	—	—	(467,590)
Gain on deconsolidation of Antero Midstream Partners LP	—	—	1,406,042
Interest expense, net	(268,701)	(286,743)	(228,111)
Gain (loss) on early extinguishment of debt	(1,500)	—	36,419
Total other income (expenses)	(250,007)	(246,463)	619,799
Income (loss) before income taxes	490,086	(174,558)	(367,246)
Provision for income tax benefit	295,051	128,857	74,110
Net income (loss) and comprehensive income (loss) including noncontrolling interests	785,137	(45,701)	(293,136)
Net income and comprehensive income attributable to noncontrolling interests	170,067	351,816	46,993
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 615,070	$ (397,517)	(340,129)
Income (loss) per common share—basic	$ 1.95	$ (1.26)	(1.11)
Income (loss) per common share—assuming dilution	$ 1.94	$ (1.26)	(1.11)
Weighted average number of shares outstanding:			
Basic	315,426	316,036	306,400
Diluted	316,283	316,036	306,400

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION
Consolidated Statements of Equity
Years Ended December 31, 2017, 2018 and 2019
(In thousands)

	Common Stock		Additional paid-in capital	Accumulated earnings	Noncontrolling interests	Total equity
	Shares	Amount				
Balances, December 31, 2016	314,877	$ 3,149	5,299,481	959,995	1,465,953	7,728,578
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,502	15	(18,244)	—	—	(18,229)
Issuance of common units by Antero Midstream Partners LP, net of underwriter discounts and offering costs	—	—	—	—	248,956	248,956
Issuance of common units by Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(15,636)	—	9,691	(5,945)
Sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation, net of tax	—	—	206,486	—	(19,940)	186,546
Equity-based compensation	—	—	93,669	—	9,776	103,445
Net income and comprehensive income	—	—	—	615,070	170,067	785,137
Effects of changes in ownership interests in consolidated subsidiaries	—	—	1,005,196	—	(1,005,196)	—
Distributions to noncontrolling interests	—	—	—	—	(152,352)	(152,352)
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)
Repurchases and retirements of common stock	(9,145)	(91)	(128,993)	—	—	(129,084)
Equity-based compensation	—	—	62,618	—	7,796	70,414
Net income (loss) and comprehensive income (loss)	—	—	—	(397,517)	351,816	(45,701)
Effects of changes in ownership interests in consolidated subsidiaries	—	—	8,637	—	(8,637)	—
Distributions to noncontrolling interests	—	—	—	—	(267,271)	(267,271)
Other	—	—	—	—	3	3
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)
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)
Distributions to noncontrolling interests	—	—	—	—	(85,076)	(85,076)
Effect of deconsolidation of Antero Midstream Partners LP	—	—	(336,172)	—	(784,744)	(1,120,916)
Balances, December 31, 2019	295,941	$ 2,959	6,130,365	837,419	—	6,970,743

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION
Consolidated Statements of Cash Flows
Years Ended December 31, 2017, 2018 and 2019
(In thousands)

	Year Ended December 31,		
	2017	2018	2019
Cash flows provided by (used in) operating activities:			
Net income (loss) and comprehensive income (loss) including noncontrolling interests	$ 785,137	(45,701)	(293,136)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion	827,220	975,284	918,629
Impairments	183,029	559,095	1,782,816
Commodity derivative fair value (gains) losses	(658,283)	87,594	(463,972)
Gains on settled commodity derivatives	213,940	243,112	325,090
Premium paid on derivative contracts	—	(13,318)	—
Proceeds from derivative monetizations	749,906	370,365	—
Marketing derivative fair value gains	21,394	(94,081)	—
Gains on settled marketing derivatives	—	72,687	—
Deferred income tax benefit	(295,126)	(128,857)	(79,158)
Loss on sale of assets	—	—	951
Equity-based compensation expense	103,445	70,414	23,559
Loss (gain) on early extinguishment of debt	1,500	—	(36,419)
Loss on sale of Antero Midstream Corporation shares	—	—	108,745
Equity in earnings (loss) of unconsolidated affiliates	(20,194)	(40,280)	143,216
Water earnout	—	—	(125,000)
Distributions/dividends of earnings from unconsolidated affiliates	20,195	46,415	157,956
Gain on deconsolidation of Antero Midstream Partners LP	—	—	(1,406,042)
Other	(1,907)	4,681	10,681
Changes in current assets and liabilities:			
Accounts receivable	(5,214)	(15,156)	31,631
Accrued revenue	(38,162)	(174,706)	156,941
Other current assets	(2,755)	(5,817)	(1,025)
Accounts payable including related parties	9,462	9,307	(27,996)
Accrued liabilities	64,862	63,562	(25,762)
Revenue distributions payable	45,628	101,210	(102,839)
Other current liabilities	2,214	(3,823)	4,592
Net cash provided by operating activities	2,006,291	2,081,987	1,103,458
Cash flows provided by (used in) investing activities:			
Additions to proved properties	(175,650)	—	—
Additions to unproved properties	(204,272)	(172,387)	(88,682)
Drilling and completion costs	(1,281,985)	(1,488,573)	(1,254,118)
Additions to water handling and treatment systems	(194,502)	(97,699)	(24,416)
Additions to gathering systems and facilities	(346,217)	(444,413)	(48,239)
Additions to other property and equipment	(14,127)	(7,514)	(6,700)
Investments in unconsolidated affiliates	(235,004)	(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
Change in other assets	(12,029)	(3,663)	7,091
Proceeds from asset sales	2,156	—	1,983
Net cash used in investing activities	(2,461,630)	(2,350,724)	(1,041,490)
Cash flows provided by (used in) financing activities:			
Issuance of common units by Antero Midstream Partners LP	248,956	—	—
Proceeds from sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation	311,100	—	—
Repurchases of common stock	—	(129,084)	(38,772)
Issuance of senior notes by Antero Midstream Partners LP	—	—	650,000
Repayment of senior notes	—	—	(191,092)
Borrowings on bank credit facilities, net	90,000	660,379	232,000
Payments of deferred financing costs	(16,377)	(2,169)	(4,547)
Distributions to noncontrolling interests in Antero Midstream Partners LP	(152,352)	(267,271)	(85,076)
Employee tax withholding for settlement of equity compensation awards	(24,174)	(17,020)	(2,389)
Other	(4,983)	(4,539)	(2,560)
Net cash provided by financing activities	452,170	240,296	557,564
Antero Midstream Partners LP cash at deconsolidation	—	—	(619,532)
Net decrease in cash and cash equivalents	(3,169)	(28,441)	—
Cash and cash equivalents, beginning of period	31,610	28,441	—
Cash and cash equivalents, end of period	$ 28,441	—	—

ANTERO RESOURCES CORPORATION
Consolidated Statements of Cash Flows
Years Ended December 31, 2017, 2018 and 2019
(In thousands)

	Year Ended December 31,		
	2017	**2018**	**2019**
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 263,919	275,769	224,331
Decrease in accounts payable and accrued liabilities for additions to property and equipment	$ (547)	(47,717)	(15,897)

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 exploration, development, 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, 2018 and 2019, and the results of its operations and its cash flows for the years ended December 31, 2017, 2018 and 2019. 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. Operating results for the year ended December 31, 2019 are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received for natural gas, NGLs, and oil, natural production declines, the uncertainty of exploration and development drilling results, fluctuations in the fair value of derivative instruments, and other factors.

(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 to the consolidated financial statements), our ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and we consolidated Antero Midstream Partners' financial position and results of operations into our consolidated financial statements. The Transactions (defined in Note 3 to the consolidated financial statements) resulted in the exchange of the limited partner interest we 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, we no longer hold a controlling interest in Antero Midstream Partners and we now have 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.

On December 16, 2019, the Company sold 19,377,592 shares of Antero Midstream Corporation's common stock to Antero Midstream at a price of $5.1606 per share, which shares were thereafter cancelled by Antero Midstream Corporation, resulting in aggregate proceeds to the Company of $100 million. This reduced Antero's interest in Antero Midstream Corporation to approximately 28.7% at December 31, 2019. See Note 3 to the consolidated financial statements for further discussion of the Transactions.

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 represents the interests in Antero Midstream Partners, which were owned by the public prior to the Transactions, and the incentive distribution rights in Antero Midstream Partners, in both cases during the periods prior to the Transactions. Noncontrolling interests in consolidated subsidiaries is included as a component of equity in the Company's consolidated balance sheets.

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 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 Investments in unconsolidated affiliates on the Company's consolidated balance sheets. Income from investees that are accounted for under the equity method is included in Equity in earnings of unconsolidated affiliates on the Company's consolidated statements of operations and cash flows. When Antero records its proportionate share of net income, it increases equity income in the statements of operations and comprehensive income (loss) and the carrying value of that investment on the Company's balance sheet. When a distribution is received, it is recorded as a reduction to the carrying value of that investment on the 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 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, and liabilities, as well as 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, equity-based compensation, asset retirement obligations, depreciation, amortization, 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 transportation capacity 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, 2019, the book overdraft included within accounts payable and revenue distributions payable were $7 million and $18 million, respectively. As of December 31, 2018, the book overdraft included within accounts payable and revenue distributions payable were $10 million and $28 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. The Company incurred no such charges to expense during the years ended December 31, 2017 and 2018. During the year ended December 31, 2019, we recorded an impairment charge of $26 million for design and initial costs related to pads that are no longer planned to be placed into service. 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, and future plans to develop acreage, as well as 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 $160 million, $549 million, and $393 million for the years ended December 31, 2017, 2018 and 2019, 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 charge 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, future commodity prices, future production estimates, and anticipated capital expenditures, using a commensurate discount rate.

During the year ended December 31, 2019, the carrying amount of the Utica Shale exceeded the estimated undiscounted future cash flows based on future commodity prices at September 30, 2019. We estimated the fair value of the Utica Shale assets based on sales of other properties. As a result, the Company recorded an impairment charge of $881 million related to proved properties in the Utica Shale during the year ended December 31, 2019. The Company did not record any impairment expenses associated with its proved properties during the years ended December 31, 2017 and 2018, nor did it incur any impairment expenses related to proved properties in the Marcellus Shale during the year ended December 31, 2019.

At December 31, 2019, 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.

The provision for 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 $694 million, $832 million, and $884 million for the years ended December 31, 2017, 2018 and 2019, respectively.

(g) Gathering Pipelines, Compressor Stations, and Water Handling and Treatment Systems

Expenditures for construction, installation, major additions, and improvements to property, plant, and equipment that are not directly related to production are capitalized, whereas minor replacements, maintenance, and repairs are expensed as incurred. Gathering pipelines and compressor stations are depreciated using the straight-line method over their estimated useful lives of 50 years. Water handling and treatment systems are depreciated using the straight-line method over their estimated useful lives of 5 to 20 years. Depreciation expense for gathering pipelines, compressor stations, and water handling and treatment systems was $120 million, $131 million, and $22 million for the years ended December 31, 2017, 2018 and 2019, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

Due to the deconsolidation of Antero Midstream Partners, effective March 13, 2019, gathering pipelines, compressor stations, and water handling and treatment systems owned by Antero Midstream Partners are no longer included in the consolidated financial statements.

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.

(h) 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 $23 million, $10 million and $15 million during the years ended December 31, 2017, 2018 and 2019, respectively, and were associated with midstream assets.

(i) Other Property and Equipment

Other property and equipment assets are depreciated using the straight-line method over their estimated useful lives, which range from 2 to 20 years. Depreciation expense for other property and equipment was $10 million, $9 million, and $8 million for the years ended December 31, 2017, 2018 and 2019, respectively. A gain or loss is recognized upon the sale or disposal of other property and equipment.

(j) Deferred Financing Costs

Deferred financing 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 facilities, 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. These costs are amortized over the term of the related debt instrument. The Company charges expense for unamortized deferred financing costs if credit facilities are retired prior to their maturity date. At December 31, 2019, the Company had $7 million of unamortized deferred financing costs included in other long-term assets, and $19 million of unamortized deferred financing 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, $13 million, and $11 million for the years ended December 31, 2017, 2018 and 2019, respectively.

(k) 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.

(l) 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.

(m) 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, 2018 and 2019, 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.

(n) Natural Gas, NGLs, and Oil Revenues

On May 28, 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers*, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU replaced most existing revenue recognition guidance in GAAP when it became effective and was incorporated into GAAP as Accounting Standards Codification ("ASC") Topic 606. The Company elected the modified retrospective transition method when new standard became effective for the Company on January 1, 2018. The adoption of ASU 2014-09 did not have a material impact on the Company's financial results.

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. Sales of natural gas, NGLs, and oil are recognized when we satisfy a performance obligation by transferring control of a product to a customer. Payment is generally received in the month following the sale.

Under our natural gas sales contracts, we deliver natural gas to the purchaser at an agreed upon delivery point. Natural gas is transported from our wellheads to delivery points specified under sales contracts. To deliver natural gas to these points, Antero Midstream Corporation or third parties gather, compress, process and transport our natural gas. We maintain control of the natural gas during gathering, compression, processing, and transportation. Our sales contracts provide that we receive a specific index price adjusted for pricing differentials. We transfer control of the product at the delivery point and recognize revenue based on the contract price. The costs to gather, compress, process and transport the natural gas are recorded as Gathering, compression, processing and transportation expenses.

NGLs, which are extracted from natural gas through processing, are either sold by us directly or by the processor under processing contracts. For NGLs sold by us directly, our sales contracts provide that we deliver the product to the purchaser at an agreed upon delivery point and that we receive a specific index price adjusted for pricing differentials. We transfer control of the product to the purchaser at the delivery point and recognize revenue based on the contract price. The costs to process and transport NGLs are recorded as Gathering, compression, processing, and transportation expenses. For NGLs sold by the processor, our processing contracts provide that we transfer control to the processor at the tailgate of the processing plant and we recognize revenue based on the price received from the processor.

Under our oil sales contracts, we generally sell oil to purchasers and collect a contractually agreed upon index price, net of pricing differentials. We recognize revenue based on the contract price when we transfer control of the product to a purchaser.

(o) 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. We retain control of the purchased natural gas and NGLs prior to delivery to the purchaser. We have concluded that we are the principal in these arrangements and therefore we recognize 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 our produced natural gas and NGLs. We satisfy performance obligations to the purchaser by transferring control of the product at the delivery point and recognize revenue based on the price received from the purchaser. Fees generated from the sale of excess firm transportation marketed to third parties are included in 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.

(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 our 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 to the consolidated financial statements for further discussion on the Transactions and Note 18 to the consolidated financial statements for disclosures on the Company's reportable segments. The portion of such fees shown in our 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 satisfies its performance obligations and recognizes revenue when low pressure volumes are delivered to a compressor station, high pressure volumes are delivered to a processing plant or transmission pipeline, and compression volumes are delivered to a high pressure line. Revenue is 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 satisfies its performance obligations and recognizes revenue when the fresh water volumes have been delivered to the hydration unit of a specified well pad and the wastewater volumes have been delivered to its wastewater treatment facility. For services contracted through third-party providers, Antero Midstream Partners' performance obligation is satisfied when the service performed by the third-party provider has been completed. Revenue is 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, 2017, 2018 and 2019 are as follows:

	2017	2018	2019
Company A	4 %	8 %	16 %
Company B	14	6	15
Company C	20	13	9
Company D	—	14	3
All others	62	59	57
	100 %	100 %	100 %

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 14 different counterparties. The fair value of the Company's commodity net derivative contracts is approximately $746 million at December 31, 2019 and primarily includes the following net asset values by bank counterparty: Wells Fargo - $215 million; JP Morgan - $134 million; Morgan Stanley - $121 million; Citigroup - $117 million; Scotiabank - $58 million; Canadian Imperial Bank of Commerce - $44 million; PNC - $29 million; BNP Paribas - $21 million; Natixis - $10 million; and SunTrust $7 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) at December 31, 2019 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 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

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) our 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, the results of Antero Midstream Partners are no longer consolidated in Antero's results; however, the Company's segment disclosures include our equity method investment in Antero Midstream Corporation due to its significance to the Company's operations. See Note 3 to the consolidated financial statements for further discussion on the Transactions and Note 18 to the consolidated financial statements for disclosures on the Company's reportable segments.

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—assuming dilution for each period is computed after giving consideration to the potential dilution from outstanding equity awards, calculated using the treasury stock method. The Company includes performance share unit awards 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,		
	2017	2018	2019
Basic weighted average number of shares outstanding	315,426	316,036	306,400
Add: Dilutive effect of restricted stock units	817	—	—
Add: Dilutive effect of outstanding stock options	—	—	—
Add: Dilutive effect of performance stock units	40	—	—
Diluted weighted average number of shares outstanding	316,283	316,036	306,400
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings per common share [(1)]:			
Restricted stock units	1,521	2,844	2,357
Outstanding stock options	676	626	527
Performance stock units	1,054	1,705	1,443

(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.

(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 issued, to the balance of additional paid-in capital as of retirement.

(w) Recently Issued Accounting Standards

In August 2018, the FASB issued ASU No. 2018-13, "Fair Value Measurement: Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurement," which provides changes to certain fair value disclosure requirements. This ASU is effective for annual reporting periods beginning after December 15, 2019 and interim periods within those annual periods, with early adoption permitted. The adoption of this update is not expected to have a material impact on the Company's consolidated financial statements.

(x) Equity-Based Compensation

We recognize compensation cost related to all equity-based awards in the financial statements based on their estimated grant date fair value. We are 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 9 for additional information regarding our equity-based compensation.

(3) Deconsolidation of Antero Midstream Partners LP

In 2014, the Company formed Antero Midstream Partners to own, operate, and develop midstream energy assets that service Antero's 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 Antero under long-term, fixed-fee contracts.

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's common stock, par value $0.01 per share, in consideration for 98,870,335 common units representing limited partnership interests in Antero Midstream Partners.

Prior to the Closing, the Company's ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and the Company consolidated Antero Midstream Partners' financial position and results of operations into its consolidated financial statements. The Transactions resulted in the exchange of limited partner interests in Antero Midstream Partners owned by Antero for common stock of Antero Midstream Corporation representing an approximate 31% interest as of March 12, 2019. As a result, the Company no longer held a controlling interest in Antero Midstream Partners and the Company held an interest in Antero Midstream Corporation that provided significant influence, but not control, over Antero Midstream Corporation. Thus, effective March 13, 2019, the Company no longer consolidates Antero Midstream Partners in our consolidated financial statements and accounts for its interest in Antero Midstream Corporation using the equity method of accounting. In addition, 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 5 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
Other 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) Revenue

(a) *Disaggregation of Revenue*

Revenue is disaggregated by type (in thousands) in the following table. The table also identifies which reportable segment that the disaggregated revenues relate. For more information on reportable segments, see Note 18—Segment Information.

	Year ended December 31,			
	2017	2018	2019	Segment to which revenues relate
Revenues from contracts with customers:				
Natural gas sales	$ 1,769,284	$ 2,287,939	2,247,162	Exploration and production
Natural gas liquids sales (ethane)	93,041	172,653	124,563	Exploration and production
Natural gas liquids sales (C3+ NGLs)	777,400	1,005,124	1,094,599	Exploration and production
Oil sales	108,195	187,178	177,549	Exploration and production
Gathering and compression [(1)]	11,386	17,817	3,972	Equity method investment in AMC
Water handling and treatment [(1)]	1,334	3,527	506	Equity method investment in AMC
Marketing	258,045	458,901	292,207	Marketing
Total	3,018,685	4,133,139	3,940,558	
Revenue from derivatives and other sources	636,889	6,487	468,132	
Total revenue and other	$ 3,655,574	$ 4,139,626	4,408,690	

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

(b) *Transaction Price Allocated to Remaining Performance Obligations*

For our product sales that have a contract term greater than one year, we have 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 our 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 our product sales that have a contract term of one year or less, we have 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 our sales contracts, we invoice customers after our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under ASC 606. At December 31, 2018 and 2019, our receivables from contracts with customers were $475 million and $318 million, respectively.

(5) Equity Method Investments

At December 31, 2019, Antero owned approximately 28.7% of Antero Midstream Corporation's common stock, which is reflected in the Company's consolidated financial statements using the equity method of accounting. See Note 3 to the consolidated financial statements for further discussion on the Transactions.

Prior to March 13, 2019, our 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 on February 6, 2017 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 of Antero Midstream Corporation.

At December 31, 2019, we determined that events and circumstances indicated that the carrying value had experienced an other-than-temporary decline and we recorded an impairment of $468 million. The fair value of the equity method investment in Antero Midstream Corporation was based on the quoted market share price of Antero Midstream Corporation at December 31, 2019 (Level 1).

The following table is a reconciliation of investments in unconsolidated affiliates for the years ending December 31, 2018 and 2019 in thousands):

	Stonewall [1]	MarkWest Joint Venture	Antero Midstream Corporation [2]	Total
Balance at December 31, 2017	$ 67,128	236,174	—	303,302
Investments [3]	—	136,475	—	136,475
Equity in net income of unconsolidated affiliates	10,740	29,540	—	40,280
Distributions from unconsolidated affiliates	(9,765)	(36,650)	—	(46,415)
Balance at 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
Balance at December 31, 2019	$ —	—	1,055,177	1,055,177

(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 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) In December 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 in Antero Midstream Corporation recorded as of December 31, 2019 to reduce the carrying value to fair value.

(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.

Summarized Financial Information of Antero Midstream Corporation

The following tables present summarized financial information of Antero Midstream Corporation. Summarized financial information is presented from March 13, 2019.

Balance Sheet

(in thousands)		December 31, 2019
Current assets	$	108,558
Noncurrent assets		6,174,320
Total assets	$	6,282,878
Current liabilities	$	242,084
Noncurrent liabilities		2,897,380
Stockholders' equity		3,143,414
Total liabilities and equity	$	6,282,878

Statement of Operations

(in thousands)		For the period March 13, 2019 through December 31, 2019
Revenues	$	792,588
Operating expenses		1,177,610
Loss from operations	$	(385,022)
Net loss attributable to the equity method investments	$	(341,565)

(6) Accrued Liabilities

Accrued liabilities as of December 31, 2018 and 2019 consisted of the following items (in thousands):

	December 31,		
		2018	2019
Capital expenditures	$	113,237	105,706
Gathering, compression, processing, and transportation expenses		148,032	134,153
Marketing expenses		67,082	52,612
Interest expense, net		43,444	30,834
Other		93,275	77,545
Total accrued liabilities	$	465,070	400,850

(7) Long-Term Debt

Long-term debt as of December 31, 2018 and 2019 consisted of the following items (in thousands):

	December 31, 2018	December 31, 2019
Antero Resources:		
Credit Facility (a)	$ 405,000	552,000
5.375% senior notes due 2021 (b)	1,000,000	952,500
5.125% senior notes due 2022 (c)	1,100,000	923,041
5.625% senior notes due 2023 (d)	750,000	750,000
5.00% senior notes due 2025 (e)	600,000	600,000
Net unamortized premium	1,241	791
Net unamortized debt issuance costs	(26,700)	(19,464)
Long-term debt	3,829,541	3,758,868
Antero Midstream Partners:(1)		
Midstream Credit Facility	990,000	—
5.375% senior notes due 2024	650,000	—
Net unamortized debt issuance costs	(7,853)	—
Long-term debt	1,632,147	—
Consolidated long-term debt	$ 5,461,688	3,758,868

(1) At December 31, 2018, Antero Midstream Partners' indebtedness was included in the consolidated financial statements of Antero. At December 31, 2019, following the deconsolidation, Antero Midstream Partners' outstanding indebtedness is no longer reflected in Antero Resources' consolidated financial statements. See Note 3 to the consolidated financial statements for further discussion on the Transactions.

(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 annual redeterminations. The borrowing base and lender commitments were each reaffirmed in the annual redetermination in April 2019. The next redetermination of the borrowing base is scheduled to occur in April 2020. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the earliest stated redemption date of any series of Antero Resources' senior notes then outstanding. In October 2019, lender commitments under the Credit Facility were increased from $2.5 billion to $2.64 billion. At December 31, 2019, the borrowing base under the Credit Facility was $4.5 billion and lender commitments were $2.64 billion.

Under the Credit Facility, "Investment Grade Period" is a period that, as long as no event of default has occurred, commences when Antero Resources elects to give notice to the Administrative Agent that Antero Resources has received at least one of (i) a BBB- or better rating from Standard & Poor's and (ii) a Baa3 or better rating from Moody's (an "Investment Grade Rating"). An Investment Grade Period can end at Antero Resources' election.

During any period that is not an Investment Grade Period, the Credit Facility is ratably secured by mortgages on substantially all of Antero Resources' properties, Antero Resources' and Antero Subsidiary Holdings LLC's ownership interests in Antero Midstream Corporation, Antero Resources' ownership interests in Antero Subsidiary Holdings LLC and Monroe Pipeline LLC, and guarantees from Antero Resources' restricted subsidiaries, as applicable. During an Investment Grade Period, the liens securing the obligations under the Credit Facility shall be automatically released (subject to the provisions of the Credit Facility). The Credit Facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and interest coverage ratios. During any period that is not an Investment Grade Period, interest is payable at a variable rate based on LIBOR or the prime rate determined by Antero Resources' election at the time of borrowing, plus an applicable rate based on Antero Resources' borrowing base utilization which ranges from 25 basis points to 225 basis points. During an Investment Grade Period, interest is payable at a variable rate based on LIBOR or the prime rate determined by Antero Resources' election at the time of borrowing, plus an applicable rate based on Antero Resources' credit rating which ranges from 12.5 basis points to 175 basis points. Antero Resources was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2018 and 2019.

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. As of December 31, 2018, Antero Resources had an outstanding balance under the Credit Facility of $405 million, with a weighted average interest rate of 3.95%, and outstanding letters of credit of $685 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from (i) 0.300% to 0.375% (during any period that is not an Investment Grade Period) of the unused portion based on utilization and (ii) 0.150% to 0.300% (during an Investment Grade Period) of the unused portion based on Antero Resources' credit rating.

(b) 5.375% Senior Notes Due 2021

On November 5, 2013, Antero Resources issued $1 billion of 5.375% senior notes due November 1, 2021 (the "2021 notes") at par. The 2021 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2021 notes rank pari passu to Antero Resources' other outstanding senior notes. The 2021 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 2021 notes is payable on May 1 and November 1 of each year. Antero Resources may redeem all or part of the 2021 notes at any time at a redemption price of 100.00%. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2021 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 2021 notes, plus accrued and unpaid interest.

(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 any time at redemption prices ranging from 101.281% currently to 100.00% on or after June 1, 2020. 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 102.813% 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) Treasury Management Facility

Antero Resources has a revolving note with a lender that is also part of the Credit Facility lending consortium that provides for up to $25 million of cash management obligations in order to facilitate Antero Resources' daily treasury management. Borrowings under the revolving note are secured by the collateral for the Credit Facility. Borrowings under the revolving note bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2020. At December 31, 2018, there was $5.4 million included in "Other current liabilities" on the Company's Consolidated Balance Sheet, and at December 31, 2019, there were no outstanding borrowings under the revolving note.

(g) Debt Repurchase Program

During the fourth quarter of 2019, we repurchased $225 million principal amount of debt at a 17% weighted average discount, including a portion of our 2021 notes and our 2022 notes. The Company recognized a gain of approximately $36 million on the early extinguishment of the debt repurchased.

(8) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2018 and 2019 (in thousands):

	2018	2019
Asset retirement obligations—December 31, 2018	$ 34,610	58,979
Obligations settled	—	(153)
Obligations incurred	9,981	2,312
Revisions to prior estimates	11,569	(2,537)
Accretion expense	2,819	3,762
Effect of deconsolidation of Antero Midstream Partners LP (1)	—	(7,518)
Asset retirement obligations—December 31, 2019	$ 58,979	54,845

(1) Effective March 13, 2019, Antero Midstream Partners is no longer consolidated in Antero Resources' results.

Revisions to prior estimates in 2019 are primarily due to a decrease in well lives. Revisions to prior estimates in 2018 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.

(9) Equity-Based Compensation

Antero Resources is authorized to grant up to 16,906,500 shares of common stock to employees and directors of the Company under the Antero Resources Corporation Long-Term Incentive Plan (the "Plan"). The Plan allows equity-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent awards, and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of Antero Resources' Board of Directors. A total of 6,297,751 shares were available for future grant under the Plan as of December 31, 2019. In January 2020, a total of 4,644,934 shares were granted as restricted stock unit awards to employees and equity awards to directors.

Antero Midstream Partner's 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 include Antero Resources). As part of the Transactions, each outstanding phantom units awards under the AMP Plan was assumed by Antero Midstream Corporation and converted into 1.8926 restricted stock units under the Antero Midstream Corporation Long Term Incentive Plan (the "AMC Plan"). Each restricted stock unit award under the AMC Plan represents a right to receive one shares of Antero Midstream Corporation's Common Stock, par value $0.01 per share ("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, 2017, 2018 and 2019 (in thousands):

	Year ended December 31,		
	2017	2018	2019
Restricted stock unit awards	$ 70,866	41,505	10,343
Stock options	2,375	1,799	355
Performance share unit awards	10,797	9,659	8,069
Antero Midstream Partners phantom unit awards (1)	17,461	15,351	3,425
Equity awards issued to directors	1,946	2,100	1,367
Total expense	$ 103,445	70,414	23,559

(1) Antero Resources recognized compensation expense for equity awards granted under both the 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 to the consolidated financial statements for further discussion on the Transactions.

Restricted Stock Unit Awards

Restricted stock unit awards vest subject to the satisfaction of service requirements. Expense related to each restricted stock unit 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 restricted stock unit award activity for the year ended December 31, 2019 is as follows:

	Number of shares	Weighted grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2018	1,712,485	$ 24.57	$ 16,080
Granted	1,745,784	$ 8.14	
Vested	(730,343)	$ 27.60	
Forfeited	(357,351)	$ 16.09	
Total awarded and unvested—December 31, 2019	2,370,575	$ 12.81	$ 6,756

Intrinsic values are based on the closing price of Antero Resources' common stock on the referenced dates. As of December 31, 2019, there was $21 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 2.4 years.

Stock Options

Stock options granted under the 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, 2019 is as follows:

	Stock options	Weighted average exercise price	Weighted remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2018	579,617	$ 50.55	5.81	$ —
Granted	—	$ —		
Exercised	—	$ —		
Forfeited	(4,250)	$ 50.18		
Expired/Cancelled	(107,734)	$ —		
Outstanding at December 31, 2019	467,633	$ 50.64	5.05	$ —
Vested or expected to vest as of December 31, 2019	467,633	$ 50.64	5.05	$ —
Exercisable at December 31, 2019	467,633	$ 50.64	5.05	$ —

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

As of December 31, 2019, all stock options were fully vested resulting in no unamortized equity-based compensation expense.

Performance Share Unit Awards

Performance Share Unit Awards Based on Stock Price Targets

In 2016, the Company granted performance share unit awards ("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.

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 ("TSR PSUs"). The number of awards actually earned with respect to the 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 TSR PSUs ranges from zero to 200% of the target number of TSR PSUs originally granted. Expense related to the 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 quarter 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, 2019 is as follows:

	Number of units	Weighted average grant date fair value
Total awarded and unvested—December 31, 2018	1,767,299	$ 26.36
Granted	1,416,378	$ 9.26
Exercised	(31,944)	$ 27.38
Cancelled - Unearned	(326,938)	$ 32.97
Forfeited	(287,512)	$ 19.38
Total awarded and unvested—December 31, 2019	2,537,283	$ 16.74

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 and 2019, and the assumptions used to determine the fair values:

	Year ended December 31, 2018	Year ended December 31, 2019
Dividend yield	— %	— %
Volatility	41 %	36 %
Risk-free interest rate	2.49 %	2.35 %
Weighted average fair value of awards granted	$ 24.85	$ 9.26

As of December 31, 2019, there was $17 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 1.8 years.

Antero Midstream Partners Phantom Unit Awards and 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 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 phantom unit awards and Antero Midstream Corporation restricted stock unit awards resulting from the conversion activity for the year ended December 31, 2019 is as follows:

	Number of units	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2018	583,000	$ 27.63	$ 12,470
Granted	5,972	$ 23.44	
Vested	(3,853)	$ 32.44	
Forfeited	(20,338)	$ 26.73	
AMP Plan Units awarded and unvested—March 12, 2019	564,781	$ 27.59	$ 13,476
Effect of conversion (1)	504,119	$ 14.58	
Vested	(362,191)	$ 14.35	
Forfeited	(48,952)	$ 14.51	
Total awarded and unvested—December 31, 2019	657,757	$ 14.71	$ 4,992

(1) Effective March 12, 2019, all outstanding phantom units under the AMP Plan were assumed by Antero Midstream Corporation and converted into restricted stock units under the AMC Plan.

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, 2019, there was $6.0 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 1.7 years.

(10) Financial Instruments

The carrying values of accounts receivable and accounts payable at December 31, 2018 and 2019 approximated market values because of their short-term nature. The carrying values of the amounts outstanding under the Credit Facility and Antero Midstream Partners' credit facility at December 31, 2018 and the Credit Facility at December 31, 2019 approximated fair value because the variable interest rates are reflective of current market conditions.

Based on Level 2 market data inputs, the fair value of senior notes was approximately $3.9 billion and $2.8 billion at December 31, 2018 and 2019, respectively.

See Note 11 to the consolidated financial statements for information regarding the fair value of derivative financial instruments.

(11) Derivative Instruments

(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, 2017, 2018 and 2019. 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.

In addition, the Company has historically also entered into natural gas collar contracts, which establish ceiling and floor prices for the sale of notional volumes of natural gas as specified in the collar contracts. Under these contracts, the Company pays the difference between the ceiling price and the published index price in the event the published index price is above the ceiling price. When the published index price is below the floor price, the Company receives the difference between the floor price and the published index price. No amounts are paid or received if the index price is between the floor and the ceiling prices. The index prices in our collars are consistent with the index prices used to sell our production.

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, 2019, the Company's fixed price natural gas, oil and NGL swap positions from January 1, 2020 through December 31, 2023 were as follows (abbreviations in the table refer to the index to which the swap position is tied, as follows: NYMEX = Henry Hub; ARA Propane = European Propane CIF ARA; FEI Propane = Propane Far East Asia Index; Mont Belvieu Butane Non-TET = Mont Belvieu Butane; Mont Belvieu Propane Non-TET = Mont Belvieu Propane; NYMEX-WTI = West Texas Intermediate):

	Natural gas MMBtu/day	Natural Gas Liquids Bbls/day	Oil Bbls/day	Weighted average index price
Three months ending March 31, 2020:				
FEI Propane ($/Gal)	—	9,883	—	$ 0.81
Mont Belvieu Butane Non-TET ($/Gal)	—	6,000	—	0.50
Mont Belvieu Propane Non-TET ($/Gal)	—	1,500	—	0.58
Total	—	17,383	—	
Year ending December 31, 2020:				
NYMEX ($/MMBtu)	2,227,500	—	—	$ 2.87
ARA Propane ($/Gal)	—	10,371	—	0.65
NYMEX-WTI ($/Bbl)	—	—	26,000	55.63
Total	2,227,500	10,371	26,000	
Year ending December 31, 2021:				
NYMEX ($/MMBtu)	2,400,000			$ 2.80
Year ending December 31, 2023:				
NYMEX ($/MMBtu)	90,000			$ 2.91

As of December 31, 2019, 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, and NGL basis swap positions, which settle on the pricing index to basis differential of Mont Belvieu Butane to the European Butane CIF ARA natural gas liquids price, were as follows:

	Natural Gas MMBtu/day	Natural Gas Liquids Bbls/day	Weighted average hedged differential
Three months ending March 31, 2020:			
ARA to Mont Belvieu Non-TET ($/Gal)		2,670	$ 0.24
Three months ending June 30, 2020:			
ARA to Mont Belvieu Non-TET ($/Gal)		1,602	$ 0.22
Year ending December 31, 2020:			
NYMEX to TCO ($/MMBtu)	60,000		$ 0.35
Year ending December 31, 2021:			
NYMEX to TCO ($/MMBtu)	40,000	—	$ 0.41
Year ending December 31, 2022:			
NYMEX to TCO ($/MMBtu)	60,000	—	$ 0.52
Year ending December 31, 2023:			
NYMEX to TCO ($/MMBtu)	50,000	—	$ 0.53
Year ending December 31, 2024:			
NYMEX to TCO ($/MMBtu)	50,000	—	$ 0.53

As of December 31, 2019, the Company had natural gas and NGL contracts for January 1, 2020 through December 31, 2021 that fix the Mont Belvieu index price to percentages of WTI as follows:

	Natural Gas Liquids Bbls/day	Weighted average payout ratio
Three months ending March 31, 2020:		
Mont Belvieu Propane to NYMEX-WTI	500	50%
Year ending December 31, 2020:		
Mont Belvieu Natural Gasoline to NYMEX-WTI	18,800	80%
Year ending December 31, 2021:		
Mont Belvieu Natural Gasoline to NYMEX-WTI	18,650	78%

(b) 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. The Company recognized a fair value loss for the year ended December 31, 2017 of $21 million. 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 year ended December 31, 2019.

(c) 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, 2018 and 2019. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	December 31, 2018		December 31, 2019	
	Balance sheet location	Fair value (In thousands)	Balance sheet location	Fair value (In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity derivatives - current	Derivative instruments	$ 245,263	Derivative instruments	$ 422,849
Commodity derivatives - noncurrent	Derivative instruments	362,169	Derivative instruments	333,174
Total asset derivatives		607,432		756,023
Liability derivatives not designated as hedges for accounting purposes:				
Commodity derivatives - current	Derivative instruments	532	Derivative instruments	6,721
Commodity derivatives - noncurrent	Derivative instruments	—	Derivative instruments	3,519
Total liability derivatives		532		10,240
Net derivatives		$ 606,900		$ 745,783

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, 2018			December 31, 2019		
	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	$ 658,830	(51,398)	607,432	$ 882,817	(126,794)	756,023
Commodity derivative liabilities	$ (51,930)	51,398	(532)	$ (137,034)	126,794	(10,240)

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, 2017, 2018 and 2019 (in thousands):

	Statement of operations location	Year ended December 31, 2017	2018	2019
Commodity derivative fair value gains (losses)	Revenue	$ 658,283	(87,594)	463,972
Marketing derivative fair value gains (losses)	Revenue	$ (21,394)	94,081	—

Commodity derivative fair value gains (losses) for the years ended December 31, 2017 and 2018, include gains of $750 million and $370 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, 2017 and 2018. There were no commodity derivatives monetizations in the year ended December 31, 2019.

The 2017 monetizations were effected by reducing the average fixed index prices on certain natural gas swap contracts maturing from 2018 through 2022 while maintaining the total volumes hedged. 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 Company's commodity derivative position presented in Note 11(a) reflects the volume and adjusted fixed price indices after the monetization.

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

(12) 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. 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 our 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 has elected the effective date method for adoption of the new leasing standard under Topic 842. 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 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 under Topic 842. 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. The Company used the collateralized incremental borrowing rate, adjusted for length of lease term, for all of its present value calculations at the initial adoption of Topic 842. Additionally, 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 as of December 31, 2019 consisted of the following items (in thousands):

	December 31, 2019	
	Operating Leases	Finance Leases
Right-of-use Assets:		
Processing plants	$ 1,460,770	—
Drilling rigs and completion services	71,662	—
Gas gathering lines and compressor stations[1]	1,308,428	—
Office space	40,491	—
Vehicles	4,983	2,328
Other office and field equipment	166	170
Total right-of-use assets	$ 2,886,500	2,498 [2]

(1) Gas gathering lines and compressor stations leases includes $1.1 billion related to Antero Midstream Corporation.
(2) Financing lease assets are recorded net of accumulated amortization of $9 million as of December 31, 2019.

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

	December 31, 2019	
	Operating Leases	Finance Leases
Location on the balance sheet:		
Short-term lease liabilities	$ 304,398	923
Long-term lease liabilities	2,582,102	1,575
Total lease liabilities	$ 2,886,500	2,498

The processing plants, gathering lines and compressor stations that are classified as lease liabilities are classified as such under ASC 842 because the Company is the sole customer of the assets and because the Company 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 statement of operations and comprehensive income (loss) for the year ended December 31, 2019 (in thousands):

Statement of Operations Location	Year ended December 31, 2019
Gathering, compression, processing, and transportation	$ 842,440
General and administrative	11,228
Contract termination and rig stacking	10,692
Total Lease Expense	$ 864,360

Costs associated with finance leases of less than $1 million for the year ended December 31, 2019. We capitalized $195 million of costs related to operating leases and less than $1 million of costs related to finance leases during the year ended December 31, 2019.

Short-term lease costs that are more than one month but less than 12 months are excluded from the above amounts and total $163 million at December 31, 2019.

Supplemental Cash Flow Information Related to Leases

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

	Year ended December 31, 2019	
	Operating Leases	Finance Leases
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash out flows related to operating leases	$ 809,667	—
Investing cash out flows related to operating leases	178,898	—
Financing cash out flows related to financing leases	—	2,507
	$ 988,565	2,507
Noncash activities:		
Right of use assets obtained in exchange for operating lease liabilities	$ 3,720,945	—
Right of use assets obtained in exchange for financing lease liabilities	$ —	—

Maturities of Lease Liabilities

The table below is a schedule of future minimum payments for operating and financing lease liabilities as of December 31, 2019 (in thousands):

(in thousands)	Operating Leases	Financing Leases	Total
2020	$ 622,056	244	622,300
2021	554,000	1,007	555,007
2022	542,952	1,205	544,157
2023	538,771	42	538,813
2024	530,003	—	530,003
Thereafter	1,851,738	—	1,851,738
Total lease payments	4,639,520	2,498	4,642,018
Less: imputed interest	(1,753,020)	—	(1,753,020)
Total	$ 2,886,500	2,498	2,888,998

As of December 31, 2019, the following future minimum payments were required for office and equipment leases:

(in thousands)	Office Leases	Equipment Leases	Total
2020	$ 6,145	3,916	10,061
2021	6,071	2,931	9,002
2022	6,027	1,205	7,232
2023	4,761	42	4,803
2024	4,792	—	4,792
Thereafter	27,258	—	27,258
Total lease payments	55,054	8,094	63,148
Less: imputed interest	(14,562)	(447)	(15,009)
Total	$ 40,492	7,647	48,139

Lease Term and Discount Rate

The table below is the Company's weighted-average remaining lease term and discount rate as of December 31, 2019:

	December 31, 2019	
	Operating Leases	**Finance Leases**
Weighted-average remaining lease term:	8.7 years	2.1 years
Weighted-average discount rate:	11.5 %	6.0 %

As of December 31, 2019, the Company had requested additional processing capacity that will be accounted for as lease modifications when the processing capacity becomes available in 2020.

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 we request 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% and 70%, respectively, of the requested capacity of such new construction for 10 years. For the year ended December 31, 2019, gathering and compression fees paid by Antero Resources related to this agreement were $643 million. As of December 31, 2019, $57 million was included within accounts payable, related parties on the Condensed Balance Sheet as due to Antero Midstream Corporation related to this agreement.

(13) Income Taxes

For the years ended December 31, 2017, 2018 and 2019, income tax expense (benefit) consisted of the following (in thousands):

	Year ended December 31,		
	2017	**2018**	**2019**
Current income tax expense (benefit)	$ 75	—	5,048
Deferred income tax benefit	(295,126)	(128,857)	(79,158)
Total income tax benefit	$ (295,051)	(128,857)	(74,110)

Income tax expense (benefit) differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 35% to the year ended December 31, 2017 and 21% to the years ended December 31, 2018 and 2019 to income or loss before taxes as a result of the following (in thousands):

	Year ended December 31, 2017	2018	2019
Federal income tax expense (benefit)	$ 171,530	(36,657)	(77,122)
State income tax expense (benefit), net of federal benefit	10,779	(12,627)	(8,826)
Change in Federal tax rate, net of state benefit [(1)]	(427,962)	—	—
Change in State tax rate, net of federal effect	—	(40,415)	24,041
Nondeductible equity-based compensation	12,098	6,079	6,920
Dividends received deduction	—	—	(4,201)
Noncontrolling interest in Antero Midstream Partners	(59,523)	(73,881)	(10,998)
Deconsolidation adjustment	—	—	(6,626)
Change in valuation allowance	(2,073)	28,116	1,325
Other	100	528	1,377
Total income tax benefit	$ (295,051)	(128,857)	(74,110)

(1) The change in the Federal tax rate was due to the passage of Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act. The passage of this legislation resulted in the Company generating a deferred tax benefit in 2017 primarily due to the reduction in the U.S. statutory rate from 35% to 21%.

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 at December 31, 2018 and 2019 is as follows (in thousands):

	2018	2019
Deferred tax assets:		
Net operating loss carryforwards	$ 734,255	560,136
Equity-based compensation	10,633	7,669
Investment in Antero Midstream	—	172,460
Other	15,726	15,754
Total deferred tax assets	760,614	756,019
Valuation allowance	(45,477)	(46,802)
Net deferred tax assets	715,137	709,217
Deferred tax liabilities:		
Unrealized gains on derivative instruments	271,747	206,677
Oil and gas properties	1,055,850	1,284,528
Investment in Antero Midstream Partners	11,258	—
Other	27,070	—
Total deferred tax liabilities	1,365,925	1,491,205
Net deferred tax liabilities	$ (650,788)	(781,987)

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 $45 million and $47 million at December 31, 2018 and 2019, respectively, related to state net operating loss ("NOL") carryforwards. The increase in the valuation allowance from $45 million at December 31, 2018 to $47 million at December 31, 2019, is due to an increase in Colorado NOLs, resulting from tax return amendments, against which a full valuation allowance has been previously established. 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 within the next year. The Company has no unrecognized tax benefit balances through December 31, 2019.

As of December 31, 2019, the Company has U.S. federal and state NOL carryforwards of $2.2 billion and $2.0 billion, respectively. The federal, Colorado, and West Virginia NOL carryforwards generated in tax years prior to 2018 expire between 2032 and 2037. The 2018 NOL carryforwards generated in these jurisdictions have no expiration date. The Pennsylvania NOL carryforwards expire between 2037 and 2038.

Tax years 2016 through 2019 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 2015 through 2019.

(14) 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, 2019 (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
2020	$ 1,105,062	55,338	5,240	304,441	317,859	1,787,940
2021	1,076,832	54,154	2,859	265,838	289,169	1,688,852
2022	1,034,009	53,606	328	285,209	258,948	1,632,100
2023	1,056,902	58,565	—	313,510	225,303	1,654,280
2024	1,016,856	58,687	—	342,348	187,655	1,605,546
Thereafter	7,907,583	152,523	—	1,377,652	474,086	9,911,844
Total	$ 13,197,244	432,873	8,427	2,888,998	1,753,020	18,280,562

(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 we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests. Refer to Note 12 to the consolidated financial statements for more information on the Company's operating and finance leases.

(15) Contingencies

Environmental

In June 2018, following site inspections conducted in September 2017 at certain of our facilities located in Doddridge County, Tyler County, and Ritchie County, West Virginia, we 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 relating to permitting and control requirements for emissions of regulated pollutants at several of our natural gas production facilities. The NOV alleges that combustion devices at these facilities did not meet applicable air permitting requirements. Separately, in June 2018, we 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. We have separately received an NOV from West Virginia Department of Environmental Protection ("WVDEP") alleging violations relating to the same issues being investigated by the EPA. We continue to negotiate with EPA and WVDEP to resolve the issues alleged in the NOVs and the information request; however, we believe that there is a reasonable possibility that these actions may result in monetary sanctions exceeding $100,000. Our operations at these facilities are not suspended, and management does not expect these matters to have a material adverse effect on our 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 our 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 a pricing dispute involving firm gas sales contracts executed June 20, 2014 (the "Contracts") that the Company began delivering gas under in January 2016. From January 2016 through July 2017 and from December 2017 through January 2018, the aggregate daily gas volumes contracted for under the Contracts was 500,000 MMBtu/day, with the aggregate daily contracted volumes having increased to 600,000 MMBtu/day from August through November 2017. The Company invoiced WGL based on the natural gas index price specified in the Contracts and WGL paid the Company based on that invoice price. However, WGL asserted that the index price was no longer appropriate under the Contracts and claimed that an undefined alternative index was more appropriate for the delivery point of the gas. In July 2016, the matter was referred to arbitration by the Colorado district court. In January 2017, the arbitration panel ruled in the Company's favor. As a result, the index price has remained as specified in the Contracts and there will be no adjustments to the invoices that have been paid by WGL, nor will future invoices to WGL be adjusted based on the same claim rejected by the arbitration panel. The arbitration panel's award was confirmed by the Colorado district court on April 14, 2017.

In March of 2017, WGL filed a second legal proceeding against the Company in Colorado district court alleging breach of contract and seeking damages of more than $30 million. In this lawsuit, WGL claimed that the Company breached its contractual obligations under the Contracts by failing to deliver "TCO pool" gas. In subsequent filings, WGL explained that its claims were based on an alleged obligation that the Company must deliver gas to the Columbia IPP Pool ("IPP Pool"). WGL asserted this exact same issue in the arbitration and it was rejected by the arbitration panel. The arbitration panel specifically found that the Delivery Point under the Contracts was at a specific geographic point in Braxton County, West Virginia, not the IPP Pool. On August 24, 2017, the Colorado district court dismissed with prejudice WGL's claims against the Company in its new lawsuit and found that the Company had not breached its Contracts with WGL by allegedly failing to deliver to the IPP Pool. The Court dismissed WGL's lawsuit because WGL had not adequately pled a claim against Antero Resources for the alleged failure to deliver "TCO pool" gas under the Contracts. WGL has appealed this decision to the Colorado Court of Appeals and on October 11, 2018 the Colorado Court of Appeals reversed the Colorado district court's decision finding that WGL had adequately pled a claim for relief and remanded the case back to the district court for further proceedings.

The Company is also actively engaged in pursuing cover damages against WGL based on WGL's failure to take receipt of all of the agreed quantities of gas required under the Contracts. WGL's failure to take the gas volumes specified in the Contracts is directly related to WGL's lack of primary firm transportation rights at the Delivery Point. The failures by WGL to take the full contracted volumes of gas began in April 2017 and continued each month through December 2017 in varying quantities. In defense of its conduct, WGL asserted to the Company that their failure to receive gas is excused by (1) the Company's failure to deliver gas to the IPP Pool or (2) alleged instances of Force Majeure under the Contracts. However, as stated above, the alleged obligation that the Company must deliver gas to the IPP Pool was already rejected by the arbitration panel. Further, the Contracts expressly prohibit a Force Majeure claim in circumstances in which the gas purchaser does not have primary firm transportation agreements in place to transport the purchased gas. In each instance that WGL failed to receive the quantity of gas required under the Contracts, the Company resold the quantities not taken and invoiced WGL for cover damages pursuant to the terms of the Contracts. WGL refused to pay for the invoiced cover damages as required by the Contracts and also short paid the Company for, among other things, certain amounts of gas received by WGL. The Company filed a lawsuit against WGL in Colorado district court on October 24, 2017 to recover its cover damages, other unpaid amounts, and interest. WGL's claims have been consolidated with Antero Resources' claims in the same district court and trial began on June 10, 2019. WGL quantified its damages claim for the alleged failure to deliver TCO Pool gas and sought approximately $40 million from Antero Resources.

On June 20, 2019, the Company was awarded a jury verdict of approximately $96 million in damages after the jury found that WGL breached the Contracts with the Company. In addition, the jury rejected WGL's claim against the Company, finding that the Company did not breach the Contracts by allegedly failing to deliver TCO Pool gas and awarding no damages in favor of WGL. On August 16, 2019, WGL filed a notice of appeal of the judgment.

Effective February 1, 2018, as a result of a recent amendment to its firm gas sales contract with WGL Midstream, Inc. that was executed on December 28, 2017, the total aggregate volumes to be delivered to WGL at the Braxton delivery point were reduced from 500,000 MMBtu/day to 200,000 MMBtu/day and in November 2018, the total aggregate contract volumes to be delivered to WGL at a delivery point in Loudoun County, Virginia increased by 330,000 MMBtu/day. This increase of 330,000 MMBtu/day is in effect for the remaining term of our gas sale contract with WGL Midstream, which expires in 2038, and these increased volumes are subject to NYMEX-based pricing. Following this increase, the aggregate contract volumes delivered to WGL total 530,000 MMBtu/day.

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.

(16) Contract Termination and Rig Stacking

During the year ended December 31, 2019, the Company incurred $14 million of costs for the delay or cancellation of drilling and completion contracts with third-party contractors.

(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 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 to the consolidated financial statements for the operating results of the Company's reportable segments.

(18) Segment Information

See Note 2(t) to the consolidated financial statements for a description of the Company's determination of its reportable segments. Revenues from gathering and processing and water handling and treatment operations 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, the results of Antero Midstream Partners were included in the consolidated financial statements of Antero Resources. Effective March 13, 2019, the results of Antero Midstream Partners are no longer consolidated in Antero Resources' result; however, the Company's segment disclosures include the results of our unconsolidated affiliates due to their significance to the Company's operations. See Note 3 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 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, 2017, 2018 and 2019 (in thousands):

	Exploration and production	Marketing	Midstream	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2017:					
Sales and revenues:					
Third-party	$ 3,406,203	236,651	12,720	—	3,655,574
Intersegment	17,358	—	759,777	(777,135)	—
Total	$ 3,423,561	236,651	772,497	(777,135)	3,655,574
Operating expenses:					
Lease operating	$ 93,758	—	189,702	(194,403)	89,057
Gathering, compression, processing, and transportation	1,441,129	—	39,147	(384,637)	1,095,639
Impairment of oil and gas properties	159,598	—	—	—	159,598
Impairment of midstream assets	—	—	23,431	—	23,431
Depletion, depreciation, and amortization	704,152	—	120,458	—	824,610
General and administrative	195,153	—	58,812	(2,769)	251,196
Other	101,980	366,281	17,165	(13,476)	471,950
Total	2,695,770	366,281	448,715	(595,285)	2,915,481
Operating income (loss)	$ 727,791	(129,630)	323,782	(181,850)	740,093
Equity in earnings of unconsolidated affiliates	$ —	—	20,194	—	20,194
Segment assets	$ 13,074,027	36,701	3,057,459	(906,697)	15,261,490
Capital expenditures for segment assets	$ 1,859,481	—	540,719	(183,447)	2,216,753

	Exploration and production	Marketing	Midstream	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	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

(19) Condensed Consolidating Financial Information

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 the Company (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 the Company or a restricted subsidiary of the Company, 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 the Company 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 Condensed Consolidating Balance Sheets at December 31, 2018 and 2019, and the related Condensed Consolidating Statements of Operations and Comprehensive Income (Loss) and Condensed Consolidating Statements of Cash Flows for the years ended December 31, 2017, 2018 and 2019, present financial information for Antero Resources on a stand-alone basis (carrying its investment in subsidiaries using the equity method), financial information for the subsidiary guarantors, financial information for the non-guarantor subsidiaries, and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. The Company’s wholly owned subsidiaries are not restricted from making distributions to the Company.

Condensed Consolidating Balance Sheet
December 31, 2018
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Accounts receivable, net	$ 49,529	—	1,544	—	51,073
Intercompany receivables	383	—	115,378	(115,761)	—
Accrued revenue	474,827	—	—	—	474,827
Derivative instruments	245,263	—	—	—	245,263
Other current assets	13,937	—	21,513	—	35,450
Total current assets	783,939	—	138,435	(115,761)	806,613
Property and equipment:					
Oil and gas properties, at cost (successful efforts method):					
Unproved properties	1,767,600	—	—	—	1,767,600
Proved properties	13,306,585	—	—	(600,913)	12,705,672
Water handling and treatment systems	—	—	1,004,793	9,025	1,013,818
Gathering systems and facilities	17,825	—	2,452,883	—	2,470,708
Other property and equipment	65,770	—	72	—	65,842
	15,157,780	—	3,457,748	(591,888)	18,023,640
Less accumulated depletion, depreciation, and amortization	(3,654,392)	—	(499,333)	—	(4,153,725)
Property and equipment, net	11,503,388	—	2,958,415	(591,888)	13,869,915
Derivative instruments	362,169	—	—	—	362,169
Investment in Antero Midstream Partners	(740,031)	—	—	740,031	—
Contingent acquisition consideration	114,995	—	—	(114,995)	—
Investments in unconsolidated affiliates	—	—	433,642	—	433,642
Other assets	31,200	—	15,925	—	47,125
Total assets	$ 12,055,660	—	3,546,417	(82,613)	15,519,464
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 44,917	—	21,372	—	66,289
Intercompany payable	111,620	—	4,141	(115,761)	—
Accrued liabilities	392,949	—	72,121	—	465,070
Revenue distributions payable	310,827	—	—	—	310,827
Derivative instruments	532	—	—	—	532
Short-term lease liabilities	2,459	—	—	—	2,459
Other current liabilities	2,162	—	2,052	4,149	8,363
Total current liabilities	865,466	—	99,686	(111,612)	853,540
Long-term liabilities:					
Long-term debt	3,829,541	—	1,632,147	—	5,461,688
Deferred income tax liability	650,788	—	—	—	650,788
Contingent acquisition consideration	—	—	114,995	(114,995)	—
Long-term lease liabilities	2,873	—	—	—	2,873
Other liabilities	55,017	—	8,081	—	63,098
Total liabilities	5,403,685	—	1,854,909	(226,607)	7,031,987
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,691,508	(1,691,508)	—
Common stock	3,086	—	—	—	3,086
Additional paid-in capital	5,471,341	—	—	1,013,833	6,485,174
Accumulated earnings	1,177,548	—	—	—	1,177,548
Total stockholders' equity	6,651,975	—	1,691,508	(677,675)	7,665,808
Noncontrolling interests in consolidated subsidiary	—	—	—	821,669	821,669
Total equity	6,651,975	—	1,691,508	143,994	8,487,477
Total liabilities and equity	$ 12,055,660	—	3,546,417	(82,613)	15,519,464

Condensed Consolidating Balance Sheet
December 31, 2019
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Accounts receivable, net	46,419	—	—	—	46,419
Accounts receivable, related parties	125,000	299,450	—	(299,450)	125,000
Accrued revenue	317,886	—	—	—	317,886
Derivative instruments	422,849	—	—	—	422,849
Other current assets	10,731	—	—	—	10,731
Total current assets	922,885	299,450	—	(299,450)	922,885
Property and equipment:					
Oil and gas properties, at cost (successful efforts method):					
Unproved properties	1,368,854	—	—	—	1,368,854
Proved properties	11,859,817	—	—	—	11,859,817
Gathering systems and facilities	5,802	—	—	—	5,802
Other property and equipment	71,895	—	—	—	71,895
	13,306,368	—	—	—	13,306,368
Less accumulated depletion, depreciation, and amortization	(3,327,629)	—		—	(3,327,629)
Property and equipment, net	9,978,739	—	—	—	9,978,739
Operating leases right-of-use assets	2,886,500	—		—	2,886,500
Derivative instruments	333,174	—	—	—	333,174
Investments in unconsolidated affiliates	243,048	812,129	—	—	1,055,177
Investments in consolidated affiliates	812,129	—	—	(812,129)	—
Other assets	21,094	—	—	—	21,094
Total assets	$ 15,197,569	1,111,579	—	(1,111,579)	15,197,569
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 14,498	—	—	—	14,498
Accounts payable, related parties	397,333	—	—	(299,450)	97,883
Accrued liabilities	400,850	—	—	—	400,850
Revenue distributions payable	207,988	—	—	—	207,988
Derivative instruments	6,721	—	—	—	6,721
Short-term lease liabilities	305,320	—	—	—	305,320
Other current liabilities	6,879	—	—	—	6,879
Total current liabilities	1,339,589	—	—	(299,450)	1,040,139
Long-term liabilities:					
Long-term debt	3,758,868	—	—	—	3,758,868
Deferred income tax liability	781,987	—	—	—	781,987
Derivative instruments	3,519	—	—	—	3,519
Long-term lease liabilities	2,583,678	—	—	—	2,583,678
Other liabilities	58,635	—	—	—	58,635
Total liabilities	8,526,276	—	—	(299,450)	8,226,826
Equity:					
Stockholders' equity:					
Common stock	2,959	—	—	—	2,959
Additional paid-in capital	5,600,714	1,341,780	—	(812,129)	6,130,365
Accumulated earnings	1,067,620	(230,201)	—	—	837,419
Total stockholders' equity	6,671,293	1,111,579	—	(812,129)	6,970,743
Total liabilities and equity	$ 15,197,569	1,111,579	—	(1,111,579)	15,197,569

Condensed Consolidating Statement of Operations and Comprehensive Income
Year Ended December 31, 2017
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 1,769,975	—	—	(691)	1,769,284
Natural gas liquids sales	870,441	—	—	—	870,441
Oil sales	108,195	—	—	—	108,195
Commodity derivative fair value gains	658,283	—	—	—	658,283
Gathering, compression, water handling and treatment	—	—	772,497	(759,777)	12,720
Marketing	258,045	—	—	—	258,045
Marketing derivative loss	(21,394)	—	—	—	(21,394)
Other income	16,667	—	—	(16,667)	—
Total revenue and other	3,660,212	—	772,497	(777,135)	3,655,574
Operating expenses:					
Lease operating	93,758	—	189,702	(194,403)	89,057
Gathering, compression, processing, and transportation	1,441,129	—	39,147	(384,637)	1,095,639
Production and ad valorem taxes	90,832	—	3,689	—	94,521
Marketing	366,281	—	—	—	366,281
Exploration	8,538	—	—	—	8,538
Impairment of unproved properties	159,598	—	—	—	159,598
Impairment of gathering systems and facilities	—	—	23,431	—	23,431
Depletion, depreciation, and amortization	705,048	—	119,562	—	824,610
Accretion of asset retirement obligations	2,610	—	—	—	2,610
General and administrative	195,153	—	58,812	(2,769)	251,196
Change in fair value of contingent acquisition consideration	—	—	13,476	(13,476)	—
Total operating expenses	3,062,947	—	447,819	(595,285)	2,915,481
Operating income	597,265	—	324,678	(181,850)	740,093
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	20,194	—	20,194
Interest	(232,331)	—	(37,262)	892	(268,701)
Loss on early extinguishment of debt	(1,205)	—	(295)	—	(1,500)
Equity in earnings (loss) of Antero Midstream	(43,710)	—	—	43,710	—
Total other expenses	(277,246)	—	(17,363)	44,602	(250,007)
Income before income taxes	320,019	—	307,315	(137,248)	490,086
Provision for income tax benefit	295,051	—	—	—	295,051
Net income and comprehensive income including noncontrolling interests	615,070	—	307,315	(137,248)	785,137
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	170,067	170,067
Net income and comprehensive income attributable to Antero Resources Corporation	$ 615,070	—	307,315	(307,315)	615,070

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)
Year Ended December 31, 2018
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 2,287,939	—	—	—	2,287,939
Natural gas liquids sales	1,177,777	—	—	—	1,177,777
Oil sales	187,178	—	—	—	187,178
Commodity derivative fair value losses	(87,594)	—	—	—	(87,594)
Gathering, compression, water handling and treatment	—	—	1,027,939	(1,006,595)	21,344
Marketing	458,901	—	—	—	458,901
Marketing derivative fair value gains	94,081	—	—	—	94,081
Gain on sale of assets	—	—	583	(583)	—
Other income	(87,217)	—	—	87,217	—
Total revenue and other	4,031,065	—	1,028,522	(919,961)	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
Production and ad valorem taxes	122,305	—	4,169	—	126,474
Marketing	686,055	—	—	—	686,055
Exploration	4,958	—	—	—	4,958
Impairment of oil and gas properties	549,437	—	—	—	549,437
Impairment of midstream assets	4,470	—	5,771	(583)	9,658
Depletion, depreciation, and amortization	842,452	—	130,013	—	972,465
Accretion of asset retirement obligations	2,684	—	135	—	2,819
General and administrative	181,305	—	61,629	(2,590)	240,344
Accretion of contingent acquisition consideration	—	—	(93,019)	93,019	—
Total operating expenses	4,328,798	—	420,952	(682,029)	4,067,721
Operating income (loss)	(297,733)	—	607,570	(237,932)	71,905
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	40,280	—	40,280
Interest expense, net	(224,977)	—	(61,906)	140	(286,743)
Equity in earnings (loss) of consolidated subsidiaries	(3,664)	—	—	3,664	—
Total other expenses	(228,641)	—	(21,626)	3,804	(246,463)
Income (loss) before income taxes	(526,374)	—	585,944	(234,128)	(174,558)
Provision for income tax benefit	128,857	—	—	—	128,857
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(397,517)	—	585,944	(234,128)	(45,701)
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	351,816	351,816
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (397,517)	—	585,944	(585,944)	(397,517)

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)
Year Ended December 31, 2019
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
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	—	—	218,360	(213,882)	4,478
Marketing	292,207	—	—	—	292,207
Other income	5,810	—	—	(1,650)	4,160
Total revenue and other	4,405,862	—	218,360	(215,532)	4,408,690
Operating expenses:					
Lease operating	146,957	—	64,818	(66,055)	145,720
Gathering, compression, processing, and transportation	2,257,133	—	—	(110,486)	2,146,647
Production and ad valorem taxes	124,202	—	—	940	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	7,800	—	6,982	—	14,782
Depletion, depreciation, and amortization	893,160	—	21,707	—	914,867
Loss on sale of assets	951	—	—	—	951
Accretion of asset retirement obligations	3,699	—	63	—	3,762
General and administrative	160,402	—	18,793	(499)	178,696
Contract termination and rig stacking	14,026	—	—	—	14,026
Accretion of contingent acquisition consideration	—	—	1,928	(1,928)	—
Total operating expenses	5,459,472	—	114,291	(178,028)	5,395,735
Operating income (loss)	(1,053,610)	—	104,069	(37,504)	(987,045)
Other income (expenses):					
Water earnout	125,000			—	125,000
Equity in earnings (loss) of unconsolidated affiliates	(49,442)	(106,038)	12,264	—	(143,216)
Equity in earnings of affiliates	15,021	—	—	(15,021)	—
Loss on the sale of equity investment shares	(108,745)	—	—	—	(108,745)
Impairment of equity investments	(143,090)	(324,500)	—	—	(467,590)
Gain on deconsolidation of Antero Midstream Partners LP	1,205,705	200,337	—	—	1,406,042
Interest expense, net	(211,296)	—	(16,815)	—	(228,111)
Gain on early extinguishment of debt	36,419	—	—	—	36,419
Total other income (expenses)	869,572	(230,201)	(4,551)	(15,021)	619,799
Income before income taxes	(184,038)	(230,201)	99,518	(52,525)	(367,246)
Provision for income tax expense	74,110	—	—	—	74,110
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(109,928)	(230,201)	99,518	(52,525)	(293,136)
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	46,993	46,993
Net income and comprehensive income attributable to Antero Resources Corporation	$ (109,928)	(230,201)	99,518	(99,518)	(340,129)

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2017
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	Eliminations	Consolidated
Cash flows provided by (used in) operating activities:					
Net income including noncontrolling interests	$ 615,070	—	307,315	(137,248)	785,137
Adjustment to reconcile net income to net cash provided by operating activities:					
Depletion, depreciation, amortization, and accretion	707,658	—	119,562	—	827,220
Change in fair value of contingent acquisition consideration	(13,476)	—	13,476	—	—
Impairment of oil and gas properties	159,598	—	—	—	159,598
Impairment of midstream assets	—	—	23,431	—	23,431
Commodity derivative fair value gains	(658,283)	—	—	—	(658,283)
Gains on settled commodity derivatives	213,940	—	—	—	213,940
Proceeds from derivative monetizations	749,906	—	—	—	749,906
Marketing derivative losses	21,394	—	—	—	21,394
Deferred income tax benefit	(295,126)	—	—	—	(295,126)
Gain on sale of assets	—	—	—	—	—
Equity-based compensation expense	76,162	—	27,283	—	103,445
Loss on early extinguishment of debt	1,205	—	295	—	1,500
Equity in earnings of Antero Midstream	43,710	—	—	(43,710)	—
Equity in earnings of unconsolidated affiliates	—	—	(20,194)	—	(20,194)
Distributions of earnings from unconsolidated affiliates	—	—	20,195	—	20,195
Other	(4,500)	—	2,593	—	(1,907)
Distributions from subsidiaries	131,598	—	—	(131,598)	—
Changes in current assets and liabilities	87,466	—	(18,160)	6,729	76,035
Net cash provided by operating activities	1,836,322	—	475,796	(305,827)	2,006,291
Cash flows provided by (used in) investing activities:					
Additions to proved properties	(175,650)	—	—	—	(175,650)
Additions to unproved properties	(204,272)	—	—	—	(204,272)
Drilling and completion costs	(1,455,554)	—	—	173,569	(1,281,985)
Additions to water handling and treatment systems	—	—	(195,162)	660	(194,502)
Additions to gathering systems and facilities	—	—	(346,217)	—	(346,217)
Additions to other property and equipment	(14,127)	—	—	—	(14,127)
Investments in unconsolidated affiliates	—	—	(235,004)	—	(235,004)
Change in other assets	(8,594)	—	(3,435)	—	(12,029)
Other	2,156	—	—	—	2,156
Net cash used in investing activities	(1,856,041)	—	(779,818)	174,229	(2,461,630)
Cash flows provided by (used in) financing activities:					
Issuance of common units by Antero Midstream	—	—	248,956	—	248,956
Sale of common units in Antero Midstream by Antero Resources Corporation	311,100	—	—	—	311,100
Borrowings (repayments) on bank credit facility, net	(255,000)	—	345,000	—	90,000
Payments of deferred financing costs	(10,857)	—	(5,520)	—	(16,377)
Distributions	—	—	(283,950)	131,598	(152,352)
Employee tax withholding for settlement of equity compensation awards	(18,229)	—	(5,945)	—	(24,174)
Other	(4,785)	—	(198)	—	(4,983)
Net cash provided by financing activities	22,229	—	298,343	131,598	452,170
Net increase (decrease) in cash and cash equivalents	2,510	—	(5,679)	—	(3,169)
Cash and cash equivalents, beginning of period	17,568	—	14,042	—	31,610
Cash and cash equivalents, end of period	$ 20,078	—	8,363	—	28,441

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2018
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	Eliminations	Consolidated
Cash flows provided by (used in) operating activities:					
Net income (loss) including noncontrolling interests	$ (397,517)	—	585,944	(234,128)	(45,701)
Adjustment to reconcile net income (loss) to net cash provided by operating activities:					
Depletion, depreciation, amortization, and accretion	845,136	—	130,148	—	975,284
Changes in fair value of contingent acquisition consideration	93,019	—	(93,019)	—	—
Impairment of oil and gas properties	549,437	—	—	—	549,437
Impairment of midstream assets	4,470	—	5,771	(583)	9,658
Commodity derivative fair value losses	87,594	—	—	—	87,594
Gains on settled commodity derivatives	243,112	—	—	—	243,112
Premium paid on derivative contracts	(13,318)	—	—	—	(13,318)
Proceeds from derivative monetizations	370,365	—	—	—	370,365
Marketing derivative fair value gains	(94,081)	—	—	—	(94,081)
Gains on settled marketing derivatives	72,687	—	—	—	72,687
Deferred income tax benefit	(128,857)	—	—	—	(128,857)
Gain on sale of assets	—	—	(583)	583	—
Equity-based compensation expense	49,341	—	21,073	—	70,414
Equity in earnings (loss) of consolidated subsidiaries	3,664	—	—	(3,664)	—
Equity in earnings of unconsolidated affiliates	—	—	(40,280)	—	(40,280)
Distributions of earnings from unconsolidated affiliates	—	—	46,415	—	46,415
Distributions from Antero Midstream	159,181	—	—	(159,181)	—
Other	4,681	—	2,879	(2,879)	4,681
Changes in current assets and liabilities	(26,059)	—	(788)	1,424	(25,423)
Net cash provided by operating activities	1,822,855	—	657,560	(398,428)	2,081,987
Cash flows provided by (used in) investing activities:					
Additions to unproved properties	(172,387)	—	—	—	(172,387)
Drilling and completion costs	(1,743,587)	—	—	255,014	(1,488,573)
Additions to water handling and treatment systems	—	—	(88,674)	(9,025)	(97,699)
Additions to gathering systems and facilities	103	—	(446,270)	1,754	(444,413)
Additions to other property and equipment	(7,441)	—	—	(73)	(7,514)
Investments in unconsolidated affiliates	—	—	(136,475)	—	(136,475)
Change in other assets	(72)	—	(3,591)	—	(3,663)
Change in other liabilities	—	—	2,273	(2,273)	—
Other	—	—	6,150	(6,150)	—
Net cash used in investing activities	(1,923,384)	—	(666,587)	239,247	(2,350,724)
Cash flows provided by (used in) financing activities:					
Repurchases of common stock	(129,084)	—	—	—	(129,084)
Borrowings (repayments) on bank credit facility, net	225,379	—	435,000	—	660,379
Payments of deferred financing costs	—	—	(2,169)	—	(2,169)
Distributions	—	—	(426,452)	159,181	(267,271)
Employee tax withholding for settlement of equity compensation awards	(11,491)	—	(5,529)	—	(17,020)
Other	(4,353)	—	(186)	—	(4,539)
Net cash provided by financing activities	80,451	—	664	159,181	240,296
Net decrease in cash and cash equivalents	(20,078)	—	(8,363)	—	(28,441)
Cash and cash equivalents, beginning of period	20,078	—	8,363	—	28,441
Cash and cash equivalents, end of period	$ —	—	—	—	—

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2019
(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	Eliminations	Consolidated
Cash flows provided by (used in) operating activities:					
Net income (loss) including noncontrolling interests	$ (109,928)	(230,201)	99,518	(52,525)	(293,136)
Adjustment to reconcile net income (loss) to net cash provided by operating activities:	—				
Depletion, depreciation, amortization, and accretion	896,859	—	21,770	—	918,629
Impairments	1,451,334	324,500	6,982	—	1,782,816
Commodity derivative fair value gains	(463,972)	—	—	—	(463,972)
Gains on settled commodity derivatives	325,090	—	—	—	325,090
Deferred income tax benefit	(79,158)	—	—	—	(79,158)
Loss on sale of assets	951	—	—	—	951
Equity-based compensation expense	21,082	—	2,477	—	23,559
Gain on early extinguishment of debt	(36,419)	—	—	—	(36,419)
Loss on sale of equity investment shares	108,745	—	—	—	108,745
Equity in earnings of affiliates	(15,021)	—	—	15,021	—
Equity in (earnings) loss of unconsolidated affiliates	49,442	106,038	(12,264)	—	143,216
Water earnout	(125,000)	—	—	—	(125,000)
Distributions/dividends of earnings from unconsolidated affiliates	145,351	—	12,605	—	157,956
Gain on deconsolidation of Antero Midstream Partners LP	(1,205,705)	(200,337)	—	—	(1,406,042)
Distributions from Antero Midstream Partners LP	94,391	—	—	(94,391)	—
Other	(37,991)	—	750	47,922	10,681
Changes in current assets and liabilities	29,307	—	(10,573)	16,808	35,542
Net cash provided by operating activities	1,049,358	—	121,265	(67,165)	1,103,458
Cash flows provided by (used in) investing activities:					
Additions to unproved properties	(88,682)	—	—	—	(88,682)
Drilling and completion costs	(1,274,683)	—	—	20,565	(1,254,118)
Additions to water handling and treatment systems	—	—	(24,547)	131	(24,416)
Additions to gathering systems and facilities	—	—	(48,239)	—	(48,239)
Additions to other property and equipment	(5,638)	—	(1,062)	—	(6,700)
Investments in unconsolidated affiliates	—	—	(25,020)	—	(25,020)
Proceeds from sale of common stock of Antero Midstream Corporation	100,000	—	—	—	100,000
Proceeds from the Antero Midstream Partners LP Transactions	296,611	—	—	—	296,611
Change in other assets	10,448	—	(3,357)	—	7,091
Proceeds from sale of assets	1,983	—	—	—	1,983
Net cash investing activities	(959,961)	—	(102,225)	20,696	(1,041,490)
Cash flows provided by (used in) financing activities:					—
Repurchases of common stock	(38,772)	—	—	—	(38,772)
Issuance of senior notes	—	—	650,000	—	650,000
Repayment of senior notes	(191,092)	—	—	—	(191,092)
Borrowings (repayments) on bank credit facilities, net	141,621	—	90,379	—	232,000
Payments of deferred financing costs	2,921	—	(7,468)	—	(4,547)
Distributions to noncontrolling interests in Antero Midstream Partners LP	—	—	(131,545)	46,469	(85,076)
Employee tax withholding for settlement of equity compensation awards	(2,360)	—	(29)	—	(2,389)
Other	(1,715)	—	(845)	—	(2,560)
Net cash provided by (used in) financing activities	(89,397)	—	600,492	46,469	557,564
Antero Midstream Partners LP cash at deconsolidation	—	—	(619,532)	—	(619,532)
Net increase in cash and cash equivalents	—	—	—	—	—
Cash and cash equivalents, beginning of period	—	—	—	—	—
Cash and cash equivalents, end of period	$ —	—	—	—	—

(20) Quarterly Financial Information (Unaudited)

The Company's quarterly consolidated financial information for the years ended December 31, 2018 and 2019 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 our production revenues and the fair value of commodity derivatives.

		First quarter	Second quarter	Third quarter	Fourth quarter
Year Ended December 31, 2018:					
Total operating revenues	$	1,028,101	989,344	1,076,532	1,045,649
Total operating expenses		881,607	1,022,107	1,071,728	1,092,279
Operating income (loss)		146,494	(32,763)	4,804	(46,630)
Net income (loss) and comprehensive income (loss) including noncontrolling interest		80,810	(67,275)	(77,972)	18,736
Net income attributable to noncontrolling interest		65,977	69,110	76,447	140,282
Net income (loss) attributable to Antero Resources Corporation		14,833	(136,385)	(154,419)	(121,546)
Earnings (loss) per common share—basic	$	0.05	(0.43)	(0.49)	(0.39)
Earnings (loss) per common share—assuming dilution	$	0.05	(0.43)	(0.49)	(0.39)

		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	$	3.17	0.14	(2.86)	(1.61)
Earnings (loss) per common share—diluted	$	3.17	0.14	(2.86)	(1.61)

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 investments that were material to the quarters as presented. See Note 2 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)		**2018**	**2019**
Proved properties	$	12,705,672	11,859,817
Unproved properties		1,767,600	1,368,854
		14,473,272	13,228,671
Accumulated depletion and depreciation		(3,615,680)	(3,284,330)
Net capitalized costs	$	10,857,592	9,944,341

(b) Costs Incurred in Certain Oil and Gas Activities

	Year ended December 31,		
(In thousands)	**2017**	**2018**	**2019**
Acquisition costs:			
Proved property	$ 175,650	—	—
Unproved property	204,272	172,387	88,682
Development costs	897,287	1,164,800	1,104,336
Exploration costs	384,698	323,773	149,782
Total costs incurred	$ 1,661,907	1,660,960	1,342,800

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

	Year ended December 31,		
(In thousands)	**2017**	**2018**	**2019**
Revenues	$ 2,747,920	3,652,894	3,643,873
Operating expenses:			
Production expenses	1,279,217	1,601,985	2,417,509
Exploration expenses	8,538	4,958	884
Depletion and depreciation	694,332	832,326	884,350
Impairment of oil and gas properties	159,598	549,437	1,300,444
Results of operations before income tax (expense) benefit	606,235	664,188	(959,314)
Income tax (expense) benefit	(228,096)	(156,350)	224,511
Results of operations	$ 378,139	507,838	(734,803)

(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, 2017, 2018 and 2019 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, cash flows from operations, future drilling and completion costs, and other economic factors.

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved reserves:				
December 31, 2016	9,414	957	38	15,386
Revisions	342	(22)	(6)	176
Extensions, discoveries and other additions	1,644	77	7	2,148
Production	(591)	(36)	(2)	(822)
Purchases of reserves	289	13	1	373
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

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2017	5,587	467	16	8,488
December 31, 2018	6,669	600	20	10,389
December 31, 2019	7,229	731	21	11,740
Proved undeveloped reserves:				
December 31, 2017	5,511	522	22	8,773
December 31, 2018	4,756	452	26	7,622
December 31, 2019	4,265	460	21	7,153

Significant items included in the categories of proved developed and undeveloped reserve changes for the years 2017, 2018 and 2019 in the above table include the following:

2017 Changes in Reserves

- Extensions, discoveries, and other additions of 2,148 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales.
- Purchases of 373 Bcfe related to the acquisition of developed and undeveloped leasehold acreage in both the Marcellus and Utica Shales.
- Net upward revisions of 176 Bcfe include:
    - Upward revisions of 345 Bcfe related to improved well performance.

- Net downward revisions of 188 Bcfe related to revisions to our five-year development plan. This figure includes upward revisions of 2,092 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2016 to proved undeveloped at December 31, 2017 due to their addition to our five-year development plan, and downward revisions of 2,280 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
- Upward revisions of 132 Bcfe were due to increases in prices for natural gas, NGLs, and oil.
- Downward revisions of 113 Bcfe are due to a decrease in our assumed future ethane recovery.

- We produced 822 Bcfe during the year ended December 31, 2017.

2018 Changes in Reserves

- Extensions, discoveries, and other additions of 2,781 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales.
- 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 our 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 our 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 our assumed future ethane recovery.

We 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 both the Marcellus and Utica Shales.
- 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 our 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 our 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 our 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.

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

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)	**2017**	**2018**	**2019**
Future cash inflows	$ 55,824	64,199	54,228
Future production costs	(26,375)	(30,007)	(36,524)
Future development costs	(3,312)	(3,453)	(2,772)
Future net cash flows before income tax	26,137	30,739	14,932
Future income tax expense	(4,104)	(5,505)	(1,639)
Future net cash flows	22,033	25,234	13,293
10% annual discount for estimated timing of cash flows	(13,406)	(14,756)	(7,824)
Standardized measure of discounted future net cash flows	$ 8,627	10,478	5,469

The 12-month weighted average prices used to estimate the Company's total equivalent reserves were as follows (per Mcfe):

December 31, 2017	$ 3.23
December 31, 2018	$ 3.56
December 31, 2019	$ 2.87

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

	Year ended December 31,		
(in millions)	**2017**	**2018**	**2019**
Sales of oil and gas, net of productions costs	$ (1,469)	(2,051)	(1,116)
Net changes in prices and production costs [(1)]	3,918	707	(6,729)
Development costs incurred during the period	627	755	758
Net changes in future development costs [(2)]	229	37	(92)
Extensions, discoveries and other additions	1,448	1,925	782
Acquisitions	258	—	—
Divestitures	—	—	—
Revisions of previous quantity estimates	734	(53)	(1,011)
Accretion of discount	368	1,018	1,259
Net change in income taxes	(1,159)	(563)	1,513
Changes in timing and other	386	76	(373)
Net increase (decrease)	5,340	1,851	(5,009)
Beginning of year	3,287	8,627	10,478
End of year	$ 8,627	10,478	5,469

[(1)] Includes $3.3 billion in increased production costs due to the deconsolidation of Antero Midstream Partners.
[(2)] Includes $185 million in increased future development costs due to the deconsolidation of Antero Midstream Partners.

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CORPORATE INFORMATION

BOARD OF DIRECTORS

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Chairman and CEO

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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 TYREE
Director

SENIOR MANAGEMENT

PAUL M. RADY
Chairman and CEO

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

MICHAEL N. KENNEDY
Senior Vice President – Finance
and Chief Financial Officer –
Antero Midstream

ALVYN A. SCHOPP
Chief Administrative Officer
and Regional Senior Vice President

STEVEN M. WOODWARD
Senior Vice President – Business Development

W. PATRICK ASH
Vice President – Reserves, Planning
and Midstream

DIANA O. HOFF
Senior Vice President – Operations

YVETTE K. SCHULTZ
General Counsel and Vice President – Legal

SHERI PEARCE
Chief Accounting Officer
and Director of Accounting

BRENDAN E. KRUEGER
Vice President – Finance
and Treasurer

JOHN GIANNAULA
Vice President – Human Resources
and Administration

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Vice President – Information Technology

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Vice President – Health, Safety,
and Environment

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Vice President – Midstream

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Vice President – Gas Marketing
and Transportation

DAVID A. CANNELONGO
Vice President – Liquids Marketing
and Transportation

TOFFAZZEL HAQUE
Vice President – Production

MICHAEL SMITH
Vice President – Logistics
and Cost Management

INVESTOR RELATIONS

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(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 2019 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 the exploration for and development, production, gathering and sale of natural gas, NGLs and oil, 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, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating natural gas and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, impacts of world health events, including the coronavirus (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, 2019.

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.


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