ANTERO RESOURCES Corp
Form 10-K
February 13, 2019
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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, 2018
or
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File No. 001 36120

ANTERO RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

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

(303) 357 7310

(Registrant’s telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, Par Value $0.01 Per Share	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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10 K or any amendment to this Form 10 K.

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 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $4.1 billion based on the closing price of Antero Resources Corporation's common stock as reported on that day on the New York Stock Exchange of $21.35.

The registrant had 308,651,020 shares of common stock outstanding as of February 8, 2019.

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

The information in this report includes "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 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 described under the heading "Item 1A. Risk Factors" 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.

Forward looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity, and capital required for our development program;
- natural gas, natural gas liquids ("NGLs"), and oil prices;
- timing and amount of future production of natural gas, NGLs, and oil;
- hedging strategy and results;
- ability to successfully complete our share repurchase program;
- the possibility that the proposed simplification and related transactions described elsewhere in this Annual Report on Form 10-K (the "Transactions") are not consummated in a timely manner or at all;
- the diversion of management in connection with the Transactions and the ability of the resulting entity of the Transactions to realize the anticipated benefits of the Transactions;
- ability to meet minimum volume commitments and to utilize or monetize our firm transportation commitments;
- future drilling plans;
- 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 Partners LP, ("Antero Midstream"), including the operations of its unconsolidated affiliates;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions.

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We caution investors that these forward looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incidental to our business. 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 our 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 report 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 report 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, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report on Form 10 K.

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GLOSSARY OF COMMONLY USED TERMS

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

"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.

"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.

"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 L.P. 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.

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

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

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

"MMBtu." One million British thermal units.

"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 which 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 which 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 natural gas and oil reserves, PV 10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development, and abandonment costs, using average yearly prices computed using SEC rules, before income taxes, and without giving effect to non property related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV 10 is not a financial measure calculated in accordance with 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.

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"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.

"Unit." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"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.

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PART I

Items 1 and 2. Business and Properties

Our Company and Organizational Structure

Antero Resources Corporation (individually referred to as "Antero") and its subsidiaries (collectively referred to as the "Company") are engaged in the exploration, development, production, and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2018, we held approximately 612,000 net acres of oil and gas properties located in the Appalachian Basin in West Virginia and Ohio. Our corporate headquarters are in Denver, Colorado.

Antero's consolidated subsidiary, Antero Midstream Partners LP ("Antero Midstream" or the "Partnership"), is a public master limited partnership formed to own, operate, and develop midstream energy assets to service Antero's production, drilling, and completion activities under long-term service contracts. Antero's consolidated financial statements include Antero Midstream's financial position and results of operations.

Antero Midstream GP LP ("AMGP") was originally formed as Antero Resources Midstream Management LLC ("ARMM") in 2013, to become the general partner of Antero Midstream Partners LP ("Antero Midstream"). On May 4, 2017, ARMM converted from a Delaware limited liability company to a Delaware limited partnership and changed its name to Antero Midstream GP LP in connection with its initial public offering ("IPO"). Subsequent to its IPO, AMGP indirectly controls the general partnership interest in Antero Midstream and directly controls Antero IDR Holdings LLC ("IDR LLC"), which owns the incentive distribution rights ("IDRs") in Antero Midstream. Antero Resources Corporation does not hold any financial or other interests in AMGP and does not consolidate AMGP for financial reporting purposes.

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, 2018					Three months ended December 31, 2018
	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	15,998	$ 10,802	805	486,199	3,240	2,607
Ohio Utica Shale	2,013	$ 1,787	201	125,477	494	606
Total	18,011	$ 12,589	1,006	611,676	3,734	3,213

(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, 2018, which were $2.93 per MMBtu for natural gas based on a $3.09 per MMBtu

NYMEX reference price, $25.05 per Bbl for NGLs and $56.62 per Bbl for oil for the Appalachian Basin based on a $65.66 per Bbl WTI reference price.

(2) PV 10 is a non GAAP financial measure. For a reconciliation of PV 10 to standardized measure, 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 427 locations classified as proved undeveloped and 3,307 locations classified as probable and possible. See "Item 1A. Risk Factors" for risks and uncertainties related to developing our potential well locations contained in our proved, probable, and possible reserve categories.

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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 3,734 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 that are in existence or under construction in each of our core operating areas to accommodate our current development plans.

Together, Antero and Antero Midstream operate in the following industry segments: (i) the exploration, development, and production of natural gas, NGLs, and oil, (ii) gathering and processing, (iii) water handling and treatment, and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States. Financial information for our industry segment operations is located under "Note 16 – Segment Information."

2018 and Recent Developments and Highlights

Reserves, Production, and Financial Results

As of December 31, 2018, our estimated proved reserves were 18.0 Tcfe, consisting of 11.4 Tcf of natural gas, 554 MMBbl of ethane, 498 MMBbl of C3+ NGLs, and 46 MMBbl of oil. As of December 31, 2018, 63% of our estimated proved reserves by volume were natural gas, 35% were NGLs, and 2% were oil. Proved developed reserves were 10.4 Tcfe, or 58% of total proved reserves.

For the year ended December 31, 2018, our net production totaled 989 Bcfe, or 2,709 MMcfe per day, a 20% increase compared to 822 Bcfe, or 2,253 MMcfe per day, for the year ended December 31, 2017. 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, 2018 was $3.69 per Mcfe compared to $3.34 per Mcfe for the year ended December 31, 2017. Our average realized price after the effects of gains on settled commodity derivatives was $3.94 per Mcfe for the year ended December 31, 2018 as compared to $3.60 per Mcfe for the year ended December 31, 2017.

For the year ended December 31, 2018, we generated consolidated cash flows from operations of $2.1 billion, a consolidated net loss of $398 million, Adjusted EBITDAX of $2.0 billion, and Stand-Alone Adjusted EBITDAX of $1.7 billion. This compares to consolidated cash flows from operations of $2.0 billion, consolidated net income of $615 million, Adjusted EBITDAX of $1.5 billion, and Stand-Alone Adjusted EBITDAX of $1.2 billion for the year ended December 31, 2017. 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). See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations— Stand-Alone Exploration and Production Information" for a definition of Stand-Alone Adjusted EBITDAX and a reconciliation of Stand-Alone Adjusted EBITDAX to Antero's stand-alone net income (loss). "Stand-alone" data represents information for Antero on an unconsolidated basis, reflecting Antero's investment in Antero Midstream under the equity method of accounting.

Consolidated net loss for 2018 included (i) commodity derivative fair value losses of $88 million, comprised of gains on settled derivatives of $243 million, gains on settled derivatives of $370 million related to derivatives that were either fully or partially monetized prior to their settlement dates, and a non-cash loss of $701 million on changes in the fair value of commodity derivatives, (ii) a non-cash charge of $70 million for equity-based compensation, (iii) a non-cash charge of $549 million for impairments of unproved properties, and (iv) a non-cash deferred tax benefit of $129 million.

2018 Capital Spending and 2019 Capital Budget

For the year ended December 31, 2018, our total consolidated capital expenditures were approximately $2.2 billion, including drilling and completion expenditures of $1.5 billion, leasehold additions of $172 million, gathering and compression expenditures of $444 million, water handling and treatment expenditures of $98 million, and other capital expenditures of $8 million. In response to recent oil and NGL price declines, we have reduced our consolidated capital budget for 2019 to $1.9 billion to $2.2 billion. Our budget includes: $1.1 billion to $1.25 billion for drilling and completion, $75 million to $100 million for leasehold expenditures, and $750 million to $800 million for capital expenditures by Antero Midstream, which includes $200 million for investments in

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unconsolidated affiliates. We do not budget for acquisitions. During 2019, we plan to operate an average of five drilling rigs and four completion crews and we plan to complete 115-125 horizontal wells in the Marcellus and Utica Shales in 2019. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Delevering Activities

In December 2018, we monetized part of our natural gas hedge portfolio through the unwinding of 68% of April through December 2019 swap volumes generating $248 million of proceeds and resetting 70% of 2020 swap volumes from contract prices of $3.25/MMBtu to a contract price of $3.00/MMBtu generating $122 million of net proceeds. The early settlement of 2019 swap volumes was replaced with collars for the period April through December 2019 for the same total notional quantities (433 Bcf) as the terminated forward swaps. The collars set a weighted average floor price of $2.50/MMBtu and a weighted average ceiling price of $3.37/MMBtu. Proceeds from the monetization were used to repay a portion of borrowings under Antero's revolving credit facility.

Hedge Position

At December 31, 2018, we had fixed price swap contracts in place for January 1, 2019 through December 31, 2023 for 1.5 Tcf of our projected natural gas production at a weighted average index price of $3.13 per MMBtu. These hedging contracts include contracts for the year ending December 31, 2019 of 417 Bcf of natural gas. Additionally, we have collar agreements for April 2019 through December 2019 for 433 Bcf of our projected natural gas production at a weighted average floor and ceiling of $2.50 and $3.37, respectively. We also had basis swaps for January 2019 for 7 Bcf of our projected natural gas production with pricing differentials ranging from $0.215 to $0.40.

To the extent we have hedged the price of a portion of our estimated future production through 2023, we believe this hedge position provides some certainty to cash flows supporting our future operations and capital spending plans. As of December 31, 2018, the estimated fair value of our commodity derivative contracts was approximately $607 million.

Credit Facilities

At December 31, 2018, Antero's borrowing base under its senior revolving credit facility (the "Credit Facility") was $4.5 billion and lender commitments were $2.5 billion. The maturity date of the 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, unless such series of notes is refinanced. The borrowing base under our revolving 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 2019. At December 31, 2018, we had $405 million of borrowings, with a weighted average interest rate of 3.95%, and $685 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.

At December 31, 2018, lender commitments under Antero Midstream's revolving credit facility (the "Midstream Credit Facility") were $2.0 billion. The maturity date of the facility is October 26, 2022. At December 31, 2018, Antero Midstream had $990 million of borrowings outstanding under the Midstream Credit Facility. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Midstream Credit Facility" for a description of the Midstream Credit Facility.

Share Repurchase Program

In October 2018, the Company's Board of Directors authorized a $600 million share repurchase program, subject to targeted leverage ratios and cash flow generation. During the fourth quarter of 2018, we repurchased 9.1 million shares of our common stock (approximately 3% of total shares outstanding at commencement of the program) at a total cost of approximately $129 million.

Simplification Transaction

On October 9, 2018, we announced that AMGP, Antero Midstream and certain of their affiliates entered into a Simplification Agreement (as may be amended from time to time, the "Simplification Agreement"), pursuant to which, among other things, (1) AMGP will be converted from a limited partnership to a corporation under the laws of the State of Delaware, to be named Antero Midstream Corporation (which is referred to as "New AM" and the conversion, the "Conversion"); (2) an indirect, wholly owned subsidiary of New AM will be merged with and into Antero Midstream, with Antero Midstream surviving the merger as an indirect, wholly owned subsidiary of New AM (the "Merger") and (3) all the issued and outstanding Series B Units representing limited liability company interests of Antero IDR Holdings LLC ("IDR Holdings"), a subsidiary of AMGP and the holder of all of Antero Midstream's incentive distribution rights, will be exchanged for an aggregate of approximately 17.35 million shares of New AM's common stock (the "Series B Exchange"). The Conversion, the Merger, the Series B Exchange and the other transactions contemplated by the Simplification Agreement are collectively referred to as the "Transactions." As a result of the Transactions, Antero Midstream will be a wholly owned subsidiary of New AM and former shareholders of AMGP, unitholders of Antero Midstream, including Antero, and holders of Series B Units will each own New AM's common stock. Following the completion of the simplification transaction, Antero will no longer consolidate Antero Midstream's financial position and results of operations in Antero's consolidated financial statements, and Antero will account for its interest in New AM using the equity method of accounting.

We currently own 98,870,335 of Antero Midstream's common units and will be entitled to receive consideration of \$3.00 in cash and 1.6023 shares of New AM's common stock per Antero Midstream common unit. Public unitholders of Antero Midstream will be entitled to receive a combination of \$3.415 in cash and 1.635 shares of New AM's common stock per Antero Midstream common unit. All public unitholders of Antero Midstream will be entitled to elect to receive their merger consideration in all cash, all stock, or a combination of cash and stock, and we will have the ability to elect to take a larger portion of our merger consideration in cash if the public unitholders of Antero Midstream disproportionately elect to receive stock consideration, subject in each case to proration to ensure that the aggregate amount of cash consideration paid to all Antero Midstream unitholders is an amount equal to the aggregate amount of cash that would have been paid and issued if all public unitholders of Antero Midstream received \$3.415 in cash per Antero Midstream common unit and we received \$3.00 in cash per unit, which is approximately \$598 million and the aggregate amount of equity issuable to all Antero Midstream unitholders is a number of shares of New AM's common stock equal to the aggregate number of shares that would be issued if all public unitholders of Antero Midstream received 1.635 shares per Antero Midstream common unit and we received 1.6023 shares of New AM's common stock per Antero Midstream common unit. If we elect to receive only \$3.00 in cash per Antero Midstream common unit, we are expected to own approximately 31% of New AM's common stock following the completion of the Transactions.

Special meetings of AMGP shareholders and Antero Midstream unitholders will be held on March 8, 2019 to vote on the Simplification Agreement, the Merger and the other Transactions contemplated thereby, as applicable, and all AMGP shareholders and Antero Midstream unitholders of record as of the close of business on January 11, 2019, which is the record date for the special meetings, will be entitled to vote the AMGP common shares and Antero Midstream common units, respectively, owned by them on the record date. AMGP and Antero Midstream expect the Transactions to close shortly after the special meeting date, subject to certain closing conditions under the documentation for the Transactions. AMGP and the Partnership expect to fund the cash portion of the merger consideration with borrowings under Antero Midstream's revolving credit facility.

Also on October 9, 2018, in connection with the entry into the Simplification Agreement, (1) Antero Midstream entered into a voting agreement with AMGP's shareholders owning a majority of the outstanding AMGP common shares, pursuant to which, among other things, such shareholders agreed to vote in favor of the Transactions, (2) AMGP entered into a voting agreement with us, pursuant to which, among other things, we agreed to vote in favor of the Transactions and (3) we, AMGP, certain funds affiliated with Warburg Pincus LLC and Yorktown Partners LLC (together, the "Sponsor Holders"), Paul M. Rady and Glen C. Warren, Jr. (Messrs. Rady and Warren together, the "Management Stockholders") entered into a Stockholders' Agreement, pursuant to which, among other things, we, the Sponsor Holders and the Management Holders will have the ability to designate members of the New AM board of directors under certain circumstances, effective as the closing of the Transactions.

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 SEC.

Reserves Presentation

The following table summarizes our estimated proved reserves, related Standardized measure, and PV 10 at December 31, 2016, 2017 and 2018. Total estimated proved reserves are prepared on a consolidated basis, as required by SEC Rules, using operating and capital costs on a consolidated basis. 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, 2018 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

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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 33 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, 2016, 2017, and 2018 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,		
	2016	2017	2018
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	4,426	5,587	6,669
Ethane (MMBbl)	250	268	341
C3+ NGLs (MMBbl)	151	199	259
Oil (MMBbl)	13	16	20
Total equivalent proved developed reserves (Bcfe)	6,914	8,488	10,389
Proved undeveloped reserves:			
Natural gas (Bcf)	4,988	5,511	4,756
Ethane (MMBbl)	304	260	213
C3+ NGLs (MMBbl)	252	262	238
Oil (MMBbl)	25	22	26
Total equivalent proved undeveloped reserves (Bcfe)	8,472	8,773	7,622
Total estimated proved reserves (Bcfe)	15,386	17,261	18,011
PV-10 (in millions)(1)	$ 3,676	$ 10,175	$ 12,589
Standardized measure (in millions)(1)	$ 3,287	$ 8,627	$ 10,478
Proved developed producing (Bcfe)	6,587	7,996	9,841
Proved developed non-producing (Bcfe)	327	492	548
Percent developed	45 %	49 %	58 %

(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. For more information about the calculation of Standardized measure, see Note 19 to our consolidated financial statements included in Item 8 of this Annual Report on Form 10 K.

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, 2016, 2017, and 2018:

At December 31,

(In millions, except per Mcf data)	2016(1)	2017(2)	2018(3)
Future net cash flows	$ 11,623	$ 26,137	$ 30,739
Present value of future net cash flows:			
Before income tax (PV-10)	$ 3,676	$ 10,175	$ 12,589
Income taxes	$ (389)	$ (1,548)	$ (2,111)
After income tax (Standardized measure)	$ 3,287	$ 8,627	$ 10,478

(1) 12 month average prices used at December 31, 2016 were $2.31 per MMBtu for natural gas, $13.58 per Bbl for NGLs, and $32.63 per Bbl for oil for the Appalachian Basin based on a $42.68 WTI reference price.

(2) 12 month average prices used at December 31, 2017 were $2.91 per MMBtu for natural gas, $20.40 per Bbl for NGLs, and $45.35 per Bbl for oil for the Appalachian Basin based on a $51.03 WTI reference price.

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(3) 12 month average prices used at December 31, 2018 were $2.93 per MMBtu for natural gas, $25.05 per Bbl for NGLs, and $56.62 per Bbl for oil for the Appalachian Basin based on a $65.66 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 2016, 2017, and 2018 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 2018

The following table summarizes the changes in our estimated proved reserves during 2018 (in Bcfe):

Proved reserves, December 31, 2017	17,261
Extensions, discoveries, and other additions	2,781
Performance revisions	(433)
Revisions to 5-year development plan	(742)
Price revisions	18
Revisions to ethane recovery	115
Production	(989)
Proved reserves, December 31, 2018	18,011

Extensions, discoveries, and other additions of 2,781 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales. Downward revisions of 433 Bcfe related to well performance. Net downward revisions of 742 Bcfe related to optimization to our 5-year development plan. This figure includes upward revisions of 1,722 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2017 to proved undeveloped at December 31, 2018 due to their addition to our 5-year development plan, and downward revisions of 2,464 Bcfe for locations that were not developed within 5 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 were due to an increase in our assumed future ethane recovery. Our estimated proved reserves as of December 31, 2018 totaled approximately 18.0 Tcfe, an increase of 4% 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 2018 (in Bcfe):

Proved undeveloped reserves, December 31, 2017	8,773
Extension, discoveries, and other additions	2,464
Performance revisions	(143)
Revisions to 5-year development plan	(742)
Price revisions	7
Reclassifications to proved developed reserves	(2,531)
Revisions to ethane recovery	(206)
Proved undeveloped reserves, December 31, 2018	7,622

Extensions, discoveries, and other additions during 2018 of 2,464 Bcfe of proved undeveloped reserves resulted from delineation and developmental drilling in the Marcellus and Utica Shales. Downward revisions of 143 Bcfe related to well performance. Net downward revisions of 742 Bcfe related to optimization to our 5-year development plan. This figure includes upward revisions of 1,722 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2017 to proved undeveloped at December 31, 2018 due to their addition to our 5-year development plan, and downward revisions of 2,464 Bcfe for locations that were not developed within 5 years of initial booking as proved reserves. Upward revisions of 7 Bcfe were due to increases in prices for natural gas, NGLs, and oil.

During the year ended December 31, 2018, we converted approximately 2,531 Bcfe, or 29%, of our proved undeveloped reserves to proved developed reserves at a total capital cost of approximately $862 million. We spent an additional $303 million on development costs related primarily to drilled and uncompleted wells and properties in the proved undeveloped classification at December 31, 2017, resulting in total development spending of $1.2 billion, as disclosed in Note 19 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, 2018 are approximately $3.3 billion, or $0.44 per Mcfe, over the next five years. Based on strip pricing as of December 31, 2018, 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 5-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 5-year capital to areas with expected highest rates of return and optimal lateral lengths. This resulted in the reclassification of 1,722 Bcfe of reserves from proved undeveloped to probable during the year ended December 31, 2018 due to the 5-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, 2018, an estimated 19,400 of our net leasehold acres, containing 308 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 $42 million to renew the 19,400 acres based upon current leasing authorizations and option to extend payments. Proved undeveloped reserves of 1,565 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 235 Bcfe of these proved undeveloped reserves.

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

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2016, 2017, and 2018 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 work 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 Vice President-Reservoir Engineering and Planning, W. Patrick Ash. W. Patrick Ash has served as Vice President of Reservoir Engineering and Planning since December 2017. Prior to joining Antero, 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 2001-2011, 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 which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs 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

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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 which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves which 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, 2018. We prepare internal estimates of probable and possible reserves but have not included disclosure of such reserves in this report.

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 prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

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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, 2016, 2017 and 2018. 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,		
	2016	2017	2018
Production data:			
Natural gas (Bcf)	505	591	710
C2 Ethane (MBbl)	6,396	10,539	14,221
C3+ NGLs (MBbl)	20,279	25,507	28,913
Oil (MBbl)	1,873	2,451	3,265
Combined (Bcfe)	676	822	989
Daily combined production (MMcfe/d)	1,847	2,253	2,709
Average prices before effects of derivative settlements:			
Natural gas (per Mcf)	$ 2.50	$ 2.99	$ 3.22
C2 Ethane (per Bbl)	$ 8.28	$ 8.83	$ 12.14
C3+ NGLs (per Bbl)	$ 18.74	$ 30.48	$ 34.76
Oil (per Bbl)	$ 32.73	$ 44.14	$ 57.34
Combined average sales prices before effects of derivative settlements (per Mcfe) (1)	$ 2.60	$ 3.34	$ 3.69
Combined average sales prices after effects of derivative settlements (per Mcfe) (1)	$ 4.08	$ 3.60	$ 3.94
Average Costs (per Mcfe) (2):			
Lease operating	$ 0.07	$ 0.11	$ 0.14
Gathering, compression, processing, and transportation	$ 1.70	$ 1.75	$ 1.81
Production and ad valorem taxes	$ 0.10	$ 0.11	$ 0.12
Marketing, net	$ 0.16	$ 0.13	$ 0.23
Depletion, depreciation, amortization, and accretion	$ 1.05	$ 0.86	$ 0.85
General and administrative (excluding equity-based compensation)	$ 0.16	$ 0.14	$ 0.13

(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, (but does not include proceeds from the 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) Average costs reflect our operating costs on a standalone basis for Antero, prior to the elimination of intercompany transactions for midstream and water services provided by Antero Midstream.

Productive Wells

As of December 31, 2018, we held interests in a total of 1,130 gross (1,002.2 net) producing wells on our Marcellus Shale acreage, including the following:

- 790 gross (778.7 net) horizontal wells, averaging a 99% working interest, operated by Antero.
- 98 gross (6.1 net) horizontal wells operated by other producers.
- 242 gross (217.4 net) shallow vertical wells.

As of December 31, 2018, we held interests in a total of 250 gross (200.2 net) producing wells on our Ohio Utica Shale acreage, including the following:

- 216 gross (200.1 net) horizontal wells, averaging a 93% working interest, operated by Antero.
- 34 gross (0.1 net) horizontal wells operated by other producers.

Additionally, at December 31, 2018, we had 26 net horizontal proved developed non-producing wells, and 86 gross horizontal wells (84.7 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.

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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, 2018. A majority of our developed acreage is subject to liens securing our revolving credit facility. Approximately 57% of our net Marcellus acreage and 50% 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	125,894	124,492	425,768	361,707	551,662	486,199
Utica Shale	43,515	39,326	92,922	86,151	136,437	125,477
Total	169,409	163,818	518,690	447,858	688,099	611,676

The following table provides a summary of our current gross and net acreage by county in the Marcellus Shale and the Ohio Utica Shale.

	Marcellus	
	Gross	Net
County, State	Acres	Acres
Doddridge, WV	159,242	140,346
Fayette, PA	6,153	5,423
Gilmer, WV	12,462	10,983
Harrison, WV	103,535	91,249
Lewis, WV	48	42
Marion, WV	10,529	9,279
Monongalia, WV	2,453	2,162
Pleasants, WV	5,844	5,150
Ritchie, WV	85,421	75,285
Tyler, WV	95,048	83,770
Washington, PA	202	178
Westmoreland, PA	4,117	3,628
Wetzel, WV	66,608	58,704
Total Marcellus Shale	551,662	486,199

	Ohio Utica	
	Gross	Net
	Acres	Acres
Belmont, OH	11,575	10,761
Guernsey, OH	4,206	3,766
Harrison, OH	529	529
Monroe, OH	55,726	53,840
Noble, OH	61,351	54,167
Washington, OH	3,050	2,414
Total Utica Shale	136,437	125,477

Total Marcellus and Utica Shale	688,099	611,676

Undeveloped Acreage Expirations

The following table sets forth our total gross and net undeveloped acres as of December 31, 2018 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

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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
2019	55,228	48,674	39,077	36,140	94,305	84,814
2020	35,694	31,458	14,892	13,666	50,586	45,124
2021	46,003	40,544	6,550	5,876	52,553	46,420

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2016, 2017, and 2018. 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,					
	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
Marcellus						
Development wells:						
Productive	72	71	112	111	136	134
Dry	—	—	—	—	—	—
Total development wells	72	71	112	111	136	134
Exploratory wells:						
Productive	16	16	1	1	2	2
Dry	—	—	—	—	—	—
Total exploratory wells	16	16	1	1	2	2
Utica						
Development wells:						
Productive	35	35	4	4	17	17
Dry	—	—	—	—	—	—
Total development wells	35	35	4	4	17	17
Exploratory wells:						
Productive	5	5	18	18	8	8
Dry	—	—	—	—	—	—
Total exploratory wells	5	5	18	18	8	8
Total						
Development wells:						
Productive	107	106	116	115	153	151
Dry	—	—	—	—	—	—
Total development wells	107	106	116	115	153	151
Exploratory wells:						
Productive	21	21	19	19	10	10
Dry	—	—	—	—	—	—

Total exploratory wells	21	21	19	19	10	10

The figures in the table above do not include 86 gross wells (85 net) that were drilled and uncompleted or in the process of being completed at December 31, 2018.

Delivery Commitments

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

As of December 31, 2018, our firm sales commitments through 2023 included:

Year Ending December 31,	Volume of Natural Gas (MMBtu/d)	Firm Transport Capacity Utilized (MMBtu/d)	Volume of Ethane (Bbl/day)	Volume of C3+ NGLs (Bbl/day)
2019	1,170,000	840,000	62,500	50,000
2020	1,030,000	790,000	56,500	50,000
2021	900,000	710,000	86,500	—
2022	780,000	640,000	86,500	—
2023	690,000	600,000	86,500	—

As provided in the table above, 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 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations." If our production quantities are insufficient to meet such commitments, we may purchase third party products and/or market our excess firm transportation capacity to third parties.

Gathering and Compression

Our exploration and development activities are supported by the natural gas gathering and compression assets of our subsidiary, Antero Midstream, as well as 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, 2017 and 2018, Antero Midstream spent approximately $346 million and $444 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 all of our current and future acreage in West Virginia and Ohio for gathering and compression services.

As of December 31, 2018, Antero Midstream owned and operated 289 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, 2018, 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, 2018, Antero Midstream owned and operated 108 miles of low pressure and high pressure gathering pipelines in the Utica Shale, and Antero owned and operated 8 miles of high-pressure pipelines. As of December 31, 2018, 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 contain 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 NGLs y-grade stream is separated into individual NGLs 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. Our first international ethane sales contract commenced in November 2018.

As of December 31, 2018, we had contracted with MarkWest Energy Partners L.P. to provide cryogenic processing capacity for our Marcellus and Utica Shale production as follows:

	Plant Processing Capacity (MMcf/d)	Antero 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	2Q 2019*
Sherwood 13	200	200	3Q 2019*
Smithburg 1	200	200	1Q 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

Through Antero Midstream's investment in the Joint Venture, Antero Midstream acquired a 50% non-operated equity interest in certain of the existing and future Sherwood gas processing plants. The Joint Venture also owns a 33 1/3% interest in a fractionation facility 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 on the table above. The Joint Venture provides processing services to Antero under a long-term, fixed-fee arrangement, subject to annual CPI-based adjustments.

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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 581,000 MMBtu per day. Of the 581,000 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 2028.
  - 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 Shale 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.

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- 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. 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 2019 annual production guidance, we estimate that we could incur annual net marketing costs of $0.175 per Mcfe to $0.225 per Mcfe in 2019 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.

Water Handling and Treatment Operations

On September 23, 2015, Antero contributed (i) all of the outstanding limited liability company interests of Antero Water LLC ("Antero Water") to Antero Midstream and (ii) all of the assets, contracts, rights, permits and properties owned or leased by Antero and used primarily in connection with the construction, ownership, operation, use or maintenance of its 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 fresh and recycled 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, as well as recycled water from its water treatment facility, 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, 2018, Antero Midstream had the ability to store 5.3 million barrels of fresh water in 37 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, 2018, Antero Midstream owned and operated 127 miles of buried fresh water pipelines and 76 miles of movable surface fresh water pipelines in the Marcellus Shale, as well as 25 fresh water storage facilities equipped with transfer pumps. As of December 31, 2018, Antero Midstream owned and operated 55 miles of buried fresh water pipelines and 27 miles of movable surface fresh water pipelines in the Utica Shale, as well as 12 fresh water storage facilities equipped with transfer pumps.

Antero Midstream also owns a wastewater treatment facility with a designed capacity of 60,000 barrel per day for the treatment of our flowback and produced water for subsequent use or sale for well completions. To date, the facility has run at reduced operating rates below the designed capacity and therefore not met certain completion milestones under the terms of the agreement between Antero Midstream and the construction contractor. Antero Midstream has made improvements to the facility's design and anticipates an increase in wastewater treatment volumes during 2019 as compared to 2018 and has included the final milestone completion payments under the construction contract in its 2019 capital budget.

Major Customers

For the year ended December 31, 2018, sales to Mercuria Energy America, Inc. and Tenaska Marketing Ventures accounted for approximately 16% and 14% of our total product revenues, respectively. For the year ended December 31, 2017, sales to Tenaska Marketing Ventures and WGL Midstream accounted for approximately 22% and 15% of our total product revenues, respectively. For the year ended December 31, 2016, sales to Tenaska Marketing Ventures and WGL Midstream accounted for approximately 29% and 13% of our total product revenues, respectively.

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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. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

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

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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 2017, FERC issued an order (Order No. 834) 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 $1,269,500 per violation per day.

Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtus 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

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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. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. The EPA would be required to complete any rulemaking revising the Subtitle D criteria by 2021. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. 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.

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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"). Several legal challenges to the WOTUS rule followed, and the WOTUS rule was stayed nationwide in October 2015 pending resolution of the court challenges. In January 2018, the U.S. Supreme Court determined that federal district courts have jurisdiction to review the WOTUS rule; consequently, the previously filed district court cases have been allowed to proceed, resulting in a patchwork of implementation of the rule in 22 states (including Pennsylvania and Ohio), the District of Columbia, and the U.S. territories, and stay of the rule in 28 states (including West Virginia). On December 11, 2018, the EPA and the Corps proposed a new rule that would narrow federal jurisdictional reach compared to the WOTUS rule. Several Environmental groups have signaled their intent to challenge the proposed rule. As a result of these developments, future implementation of the WOTUS rule or any new rule is uncertain at this time. To the extent the WOTUS 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. In June 2017, the EPA proposed to delay implementation of the 2016 methane rule, but in July 2017, the U.S. Court of Appeals for the District of Columbia Circuit ruled that such a stay was unlawful. In September 2018, the EPA proposed amendments to the 2016 standards that would relax the rule's fugitive emissions monitoring requirements and expand exceptions to pneumatic pump requirements, among other changes. Various industry and environmental groups separately challenged both the methane requirements and the EPA's attempts to delay implementation of the rules. In addition, in April 2018, several states filed a lawsuit that seeks to compel the EPA to issue methane performance standards for existing sources in the oil and natural gas source category. 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.

Antero has developed a program to reduce and manage its methane and air emissions by: (1) monitoring the science of climate change and air quality, (2) addressing stakeholder inquiries regarding the Company's position on climate change, methane emissions and air quality matters, (3) monitoring the Company's 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 that meets the requirements of the NSPS and EPA 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, greasing 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.

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In 2017, Antero 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.

By joining the program, Antero committed to: 1) evaluate its methane emission reduction opportunities, 2) implement methane reduction projects where feasible, and 3) annually report methane emission reduction actions to the EPA.

Recent methane emission reduction initiatives by Antero and Antero Midstream have included the following:

1) Facility LDAR inspections were conducted at twice the frequency required by regulations during 2018.
2) A burner management system that optimizes the efficiency of our combusters.
3) Implementation of three stages of pressure control on our storage tanks.
4) Improvements to our vapor recovery system such that we now incorporate up to three stages of vapor recovery in our process.
5) Low pressure separators (Green Completion Units) are used 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.
6) Pressure relief valves are tested and repaired or replaced as necessary, reducing the amount of methane that is accidently released.
7) Air actuated pneumatic controllers are used at the majority of our earlier stations and all of our new stations. The remaining stations that are not currently air actuated will be retrofitted to air. This reduces methane emissions that occur from using natural gas-operated pneumatic controllers.
8) Gas-operated compressor engine starters were replaced with air or electric starters. This reduces methane emissions that occur when using gas-operated compressor engine starters.
9) Optimized glycol recirculation rates are utilized with flash tank separators on glycol dehydration units.
10) Hot taps and pipeline pump down techniques that lower gas line pressure before maintenance are utilized.
11) Balanced well drill outs, which minimize the potential for venting of gas from our wells during the well completion process.

During 2019, Antero's methane emission reduction efforts will also include the following activities:

1) The GHG/Methane Reduction team which was established in 2018 and will begin meeting quarterly in 2019 to review emerging methane detection and quantification technologies applicable to exploration and production and Midstream Operations.
2) We periodically plug and abandon certain older vertical wells that were acquired in conjunction with property acquisitions. Plugging and abandoning older, low producing wells can reduce methane emissions.
3) Reviewing the option to replace existing gas-operated pneumatic controllers with air or electrically-operated controllers in exploration and production operations.
4) Exploring the use of lockdown thief hatches on storage tanks. These hatches reduce methane emissions.
5) Exploring applications for reducing methane emissions associated with rod packing systems in VRU compressors.
6) Reviewing options to recover gas from Midstream pigging operations.
7) Injecting blowdown gas from Midstream Operations into the fuel system at all new compressor stations.
8) Exploring the use of electric compression for new stations in our midstream operations, where feasible.
9) The replacement of TEG dehydrators with desiccant dehydrators for new stations, where feasible.

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Antero continues 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.

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. In the absence of such 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 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. In August 2017, the U.S. Department of State officially informed the United Nations of the United States' intent to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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 involving the use of diesel fuels and in February 2014 issued permitting guidance regarding such activities. Also, in May 2014, the EPA proposed rules under the Toxic

Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, no further action has been taken on the proposal. 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 the report did not find a direct link between hydraulic fracturing itself and contamination of

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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, in July 2015, the Ohio Department of Natural Resources issued final rules for horizontal drilling well-pad construction. The Ohio Legislature has also 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. The designation of previously unprotected species as threatened or 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 2018, nor do we anticipate that such expenditures will be material in 2019.

Employees

As of December 31, 2018, we had 623 full time employees, including 43 employees in executive, finance, treasury, legal, and administration, 24 in information technology, 22 in geology, 251 in production and engineering, 152 in midstream and water, 72 in land, and 59 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.

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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 with the Securities and Exchange Commission (the “SEC”) our Annual Reports on Form 10 K, our Quarterly Reports on Form 10 Q, and our Current Reports on Form 8 K. We make these documents available free of charge at www.anteroresources.com under the “Investors Relations” 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

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10 K, actually occur, our business, financial condition or results of operations could suffer.

Natural gas, NGLs, and oil prices are volatile. A substantial or extended decline in commodity 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 oil, natural gas and NGLs, including liquefied natural gas;
- the price and quantity of export of natural gas and oil, including liquefied natural gas, and NGLs;
- 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;
- 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.

Natural gas prices are affected by storage levels, weather, and production levels. In late 2014, natural gas prices in the US declined as a result of several factors including increased production by producers. Although prices have recovered periodically since then with spikes in January 2018 and November 2018, prices remain below pre-2014 levels for natural gas. NGL prices have generally fluctuated along with oil prices. Oil prices precipitously declined in

2014 from approximately $100 per BBL to under $30 per BBL in early 2016. Oil prices have recovered periodically since then, reaching the mid $70 per BBL range in 2018, but then again

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declined in late 2018 to below $50 per BBL as production increases from the United States and other oil producing countries led to a return of market concern regarding increasing global oil stocks and potential future supply and demand imbalances. Lower commodity prices reduce our product revenues, profitability, and our ability to borrow. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

If commodity prices decrease, a significant portion of our exploration and development projects could become uneconomic. This may result in significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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 "Item 1A. — 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 often uncertain before drilling commences.

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, tornados, 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 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 will 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 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. 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. 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, 2018, 42% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 7.6 Tcfe of estimated proved undeveloped reserves will require an estimated $3.3 billion of development capital over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the 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 $1.7 billion in 2018. Our board of directors has approved a capital budget for 2019 of $1.2 billion to $1.4 billion that includes $1.1 billion to $1.25 billion for drilling and completion and $75 million to $100 million for leasehold expenditures. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations and borrowings under our revolving credit facility; 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. For additional discussion of the risks regarding our ability to obtain funding, please read "Item 1A. Risk Factors – The borrowing base under our revolving credit facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs." 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 our revolving credit facility, including any potential decrease in the borrowing base.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower 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 our revolving 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.

Certain funds affiliated with Warburg, certain funds affiliated with Yorktown, Paul M. Rady and Glen C. Warren, Jr. (collectively, the "Sponsors") collectively own 100% of the general partner of, and a majority of the outstanding common shares representing limited partner interest in, Antero Midstream GP LP ("AMGP"), the owner of IDR LLC, the holder of the IDRs in Antero Midstream. Messrs. Rady and Warren also own a portion of the Series B Units in IDR LLC. Affiliates of Warburg and Yorktown, Mr. Rady and Mr. Warren serve as members of the board of directors of AMGP's general partner and board of directors of Antero Midstream's general partner, and each of Warburg and Yorktown are controlled in part by individuals who serve as members of the board of directors of AMGP's general partner and the board of directors of Antero Midstream's general partner. The Sponsors also own common units representing limited partner interests in Antero Midstream and shares of our common stock. As a result of their investments in AMGP, IDR LLC and Antero Midstream, the Sponsors may have conflicting interests with other stockholders. These 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, decisions to modify or limit the IDRs in the future, the terms of our agreements with Antero Midstream and AMGP and their respective 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 our revolving 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.

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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. 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. Our revolving credit facility and the indentures governing our senior notes currently restrict 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 our revolving credit facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs.

The borrowing base under our revolving credit facility is currently $4.5 billion, and lender commitments under our revolving credit facility are $2.5 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 2019. 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 would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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, throughout much of 2015 and 2016, the market for senior unsecured notes was unfavorable for high-yield issuers such as us. Our plans for growth require regular access to the capital and credit markets, including the ability to issue senior unsecured notes. Although the market for high-yield debt securities improved in the latter part of 2016 and intermittently throughout 2017 and 2018, 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.

Our revolving 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.

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The indentures governing our senior notes contain similar restrictive covenants. In addition, our revolving 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 our revolving credit facility impose on us.

Our revolving 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 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 our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. For additional discussion of the risks regarding our ability to obtain funding under our revolving credit facility, please read "Item 1A. Risk Factors – A sustained decline of oil and natural gas prices may affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our revolving credit facility. This may hinder or prevent us from meeting our future capital needs."

A breach of any covenant in our revolving 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 2018, we had estimated average outstanding borrowings under our revolving credit facilities of approximately $1.2 billion, 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 $12 million and a corresponding decrease in our cash flows and net income before the effects of income taxes. 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. Additionally, if development drilling costs increase significantly in the future, our hedged revenues may not be sufficient to cover our costs.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2018, we had entered into forward swap contracts and collars for approximately 2.0 Tcfe of our projected natural gas, NGLs, and oil production through December 31, 2023. Historically, we have realized a significant benefit from our hedge positions. For example, for the years ended December 31, 2017 and 2018, we received approximately $964 million and $613 million, respectively, in revenues from cash settled derivatives pursuant to our hedging arrangements, including $750 million and $370 million, respectively, for certain natural gas hedges that were monetized prior to their contractual settlement dates during the years ended December 31, 2017 and 2018. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2017 and 2018 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 2019 is hedged through either forward swaps, basis swaps, or collars. 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.

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Our derivative activities could result in financial losses or could reduce our earnings. In certain circumstances, we may have to make cash payments under our hedging arrangements and these payments could be significant.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, NGLs, and oil we enter into derivative instrument contracts for a portion of our estimated future natural gas production. At December 31, 2018, derivative instruments used for hedging include fixed price swap agreements, basis differential swap agreements, and collar agreements that mature at various dates through 2023 and cover approximately 2.0 Tcf of our projected natural gas production. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- the counterparty to the derivative instrument defaults on its contractual obligations;
- 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.

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

As of December 31, 2018, the estimated fair value of our commodity derivative contracts was approximately $607 million (excluding short-term commodity derivatives related to our marketing activities), including the following values by bank counterparty: Morgan Stanley - $115 million; JP Morgan - $102 million; Scotiabank - $97 million; Citigroup - $91 million; Wells Fargo - $80 million; Canadian Imperial Bank of Commerce - $51 million; BNP Paribas - $24 million; Bank of Montreal - $14 million; Toronto Dominion - $8 million; PNC - $8 million; SunTrust - $7 million; Natixis - $7 million; and Capital One - $3 million.

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. In addition, recent proposals have been made by U.S. regulators which would implement 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 or SA-CCR. If adopted as proposed, certain financial institutions would be required to comply with the new SA-CCR rules beginning on July 1, 2020 and the 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, gas processing, gathering and compression service and water handling and treatment 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 2037, and our water services agreement expires in 2035. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. As of December 31, 2018, our long term contractual obligations under agreements with minimum volume commitments totaled over $18.0 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 2019 annual production guidance, we estimate that we could incur annual net marketing costs of $0.175 per Mcfe to $0.225 per Mcfe in 2019 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, in years subsequent to 2019, our commitments and obligations under firm transportation agreements continue to increase and 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 plans; however, any failure of any pipeline under construction to be completed, or 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 oil and gas economically and in commercial quantities is dependent on the availability of adequate supplies of water for drilling and completion operations and access to Antero Midstream's Clearwater Facility and other water and waste disposal or recycling facilities and services at a reasonable cost and in accordance with applicable environmental rules. 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 oil and gas requires the use and disposal of significant quantities of water. The availability of Antero Midstream's Clearwater Facility and other disposal alternatives to receive all of the water produced from our wells may affect our production. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, or to timely obtain water sourcing permits or other rights, could adversely impact our operations. Additionally, the imposition of new environmental initiatives and regulations could include restrictions on our ability to obtain water or dispose of waste and adversely affect our business and operating results.

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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. Also, in May 2014, the EPA proposed rules under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, no further action has been taken on the proposal. 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 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 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, in July 2015, the Ohio Department of Natural Resources issued final rules for horizontal drilling well-pad construction. The Ohio legislature has also 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 natural gas and oil 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 raise 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—Acreage—Undeveloped Acreage Expirations."

As of December 31, 2018, we had 3,734 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 raise 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 73% 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 73% 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. In addition, approximately 43% and 50% 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 natural 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—Acreage—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 natural gas, NGLs and oil 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 natural gas, NGLs and oil 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, 2018, 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 governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of natural gas, NGLs, or oil.

Interruptions in operations at the Joint Venture's or other third-party processing facilities may adversely affect our business, financial condition and results of operations.

We have agreements with processing facilities, including those owned by the Joint Venture and other third parties, 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; and

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.

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 served 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, including 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 third parties with their contractual obligations to us and other factors. An extended interruption of access to or service from our or third-party pipelines and facilities or transportation services 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.

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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. 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 natural 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 natural 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. 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 natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, 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 the following: commodity derivative contracts ($607 million at December 31, 2018); the sale of our oil and gas production ($440 million at December 31, 2018) which we market to energy companies, end users, and refineries; the marketing of our excess firm transportation capacity ($34 million at December 31, 2018); and joint interest receivables ($21 million at December 31, 2018). Joint interest receivables arise from entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. The largest purchaser of our natural gas during the twelve months ended December 31, 2018 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.

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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, or cash flows.

Our natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing natural 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 natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order 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 in order 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 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, or 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. The distinction between FERC regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the 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.

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 $1,269,500 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.

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Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

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. In June 2017, the EPA proposed to delay implementation of the 2016 methane rule, but in July 2017, the U.S. Court of Appeals for the District of Columbia Circuit ruled that such a stay was unlawful. In September 2018, the EPA proposed amendments to the 2016 standards that would relax the rule's fugitive emissions monitoring requirements and expand exceptions to pneumatic pump requirements, among other changes. Various industry and environmental groups separately challenged both the methane requirements and the EPA's attempts to delay implementation of the rules. In addition, in April 2018, several states filed a lawsuit that seeks to compel the EPA to issue methane performance standards for existing sources in the oil and natural gas source category. 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, 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. In the absence of such 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 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. In August 2017, the U.S. Department of State officially informed the United Nations of the United States' intent to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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

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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.

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.

Natural gas operations in our operating areas can be adversely affected by regulations designed to protect various wildlife. The designation of previously unprotected species as threatened or 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 natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas 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 natural gas 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 natural gas, NGLs, and oil 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, 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.

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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.

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 make acquisitions of 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 integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our revolving credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our revolving 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, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities 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 2019 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 and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2019 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 2019 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.

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 recently 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. In the future, the Treasury Department and the Internal Revenue Service are expected 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, 2018, we have U.S. federal and state NOL carryforwards of $3.0 billion and $2.3 billion, respectively, which expire at various dates from 2019 to 2038. We expect to be able to utilize these NOL carryforwards and generate deductions to offset our future taxable income, including any gain we recognize with respect to the proposed simplification transaction. As a result, we do not expect to pay material U.S. federal and state income taxes through at least 2022. 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 recently enacted 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.

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Item 3. Legal Proceedings

Environmental

In March 2011, we received orders for compliance from federal regulatory agencies, including the U.S. Environmental Protection Agency, relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. Antero voluntarily reviewed all of its pre-2011 construction sites and entered into an agreement to restore or mitigate all areas of concern. The vast majority of the sites cited by regulators were among the sites we voluntarily reviewed. On January 31, 2019, we entered into a consent decree with state and federal regulators to settle for $3.15 million and perform restoration at these sites along with mitigation at an approved mitigation site. The settlement was filed in federal court in West Virginia on February 11, 2019, and we are awaiting approval by the court. Our operations at these locations 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.

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 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 facilities for the purpose of determining if the additional facilities have the same alleged compliance issues that were identified during the September 2017 inspections. Since receipt of the NOV and information request, we have met with the EPA to discuss the alleged compliance issues but do not yet have any indication with respect to whether, and to what extent, the NOV and information request will result in monetary sanctions; 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

The Company is the plaintiff in two lawsuits against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively, "SJGC") pending in United States District Court in Colorado. In March 2015, the Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC had short paid, and continued to short pay, the Company in connection with two nearly identical long term gas contracts. Under those contracts, SJGC are long term purchasers of 80,000 MMBtu/day of the Company's natural gas production. Deliveries under the contracts began in October 2011 and the term of the contracts continues through October 2019. The price for gas was based on specified indices in the contracts. Beginning in October 2014, SJGC began short paying the Company based on price indices unilaterally selected by SJGC and not the applicable index specified in the contracts. SJGC claimed that the index price specified in the contracts, and the index at which SJGC paid for deliveries from 2011 through September 2014, was no longer appropriate under the contracts because a market disruption event (as defined by the contract) had occurred and, as a result, a new index price was required to be determined by the parties. The Company rejected SJGC's contention that a market disruption event occurred. SJGC's actions constituted a breach of the contracts by failing to pay the Company based on the express price terms of the contracts and paying the Company based on unilaterally selected price indices in violation of the contracts' remedial provisions. On May 8, 2017, a jury in the United States District Court in Colorado returned a unanimous verdict finding in favor of Antero's positions in the lawsuit against SJGC. On July 21, 2017, final judgment on the jury's unanimous verdict was entered by the court. On August 18, 2017, SJGC filed post-judgment motions with the court. On March 23, 2018, the court denied SJGC's post-judgment motions. On April 20, 2018, SJGC appealed the final judgment to the United States Court of Appeals for the Tenth Circuit and the appeal remains pending.

Subsequent to the entry of judgment, SJGC has continued to short pay the Company on the basis of unilaterally selected price indices and not the index specified in the contract. Accordingly, on December 21, 2017, Antero filed suit against SJGC to recover for its damages since March of 2017. The second lawsuit remains pending.

Through December 31, 2018, the Company estimates that it is owed approximately $86 million (gross damages, including interest) more than SJGC has paid using the indices unilaterally selected by them. Substantially all of this amount has not been accrued in the Company's financial statements. The Company will vigorously seek recovery from SJGC of all underpayments and damages, including interest, based on the contracted price.

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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 point in Braxton, 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 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 Colorado Court of Appeals did not address the issue of whether WGL's claims were independently barred by the prior arbitration's findings.

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 gas began in April 2017 and continued each month through December 2017 in varying quantities. In defense of its conduct, WGL has 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 has failed to receive the quantity of gas required under the Contracts, the Company has resold the quantities not taken and invoiced WGL for cover damages pursuant to the terms of the Contracts. WGL has refused to pay for the invoiced cover damages as required by the Contracts and has also short paid the Company for, among other things, certain amounts of gas received by WGL. Through December 31, 2018, these damages amounted to approximately $109 million (gross damages, including interest). This amount has not been accrued in the Company's financial statements. The Company is currently pursuing its cover damages in a lawsuit filed in Colorado district court on October 24, 2017. The Company will continue to vigorously seek recovery of its cover damages and other unpaid amounts, including interest, as part of its claims against WGL. WGL's claims have been consolidated with Antero's claims in the same district court and trial is scheduled to begin on June 10, 2019. WGL has quantified its damages claim for the alleged failure to deliver TCO Pool gas and is seeking approximately $40 million from Antero.

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 delivery point in Braxton, West Virginia 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.

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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.

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 shares outstanding, our par value $0.01 per share common stock. Our common stock is traded on the New York Stock Exchange under the symbol "AR." On February 8, 2019, our common stock was held by 265 holders of record. The number of holders does not include the shareholders for whom shares 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)	Maximum Number of Shares that May Yet be Purchased Under the Plan
October 1, 2018 - October 31, 2018	3,241	$ 18.76	—	N/A
November 1, 2018 - November 30, 2018	7,103,854	$ 14.56	6,871,616	N/A
December 1, 2018 - December 31, 2018	2,389,742	$ 12.67	2,273,180	N/A

(1) The total number of shares purchased includes 3,241 shares repurchased in October, 232,538 shares repurchased in November and 116,562 shares repurchased in December, 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.

(2) In October 2018, the Company's Board of Directors authorized a $600 million share repurchase program, subject to targeted leverage ratios and cash flow generation. During the three months ended December 31, 2018, we repurchased 9,144,796 shares under this program for a total of $129 million, or an average of $14.12 per share.

Dividend Restrictions

Our ability to pay dividends is governed by (i) the provisions of Delaware 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) our revolving 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.

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Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on October 10, 2013 in each of Antero common stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe the Dow Jones U.S. Exploration and Production Index is meaningful because it is an independent, objective view of the performance of similarly sized energy companies.

Comparison of Cumulative Total Returns Among Antero Resources Corporation, the S&P 500

Index, and the Dow Jones US Exploration and Production Index

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 subsidiaries (including Antero Midstream Partners LP).

The selected statement of operations data and statement of cash flows data for the years ended December 31, 2016, 2017, and 2018 and the balance sheet data as of December 31, 2017 and 2018 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, 2014 and 2015 and the balance sheet data as of December 31, 2014, 2015 and 2016 are derived from our audited consolidated financial statements not included in Item 8 of this Annual Report on Form 10 K.

The statement of operations data for all periods presented has been recast to present the results of operations from our Piceance Basin and Arkoma Basin operations in discontinued operations. The losses on the sales of these properties were previously included in discontinued operations in 2012, with adjustments in 2013 and 2014 due to the resolution of certain liabilities recorded at the time of the sales and the settlement of final purchase price adjustments. The results from continuing operations reflect our remaining operations in the Appalachian Basin. No part of our general and administrative expenses or interest expense was allocated to discontinued operations.

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The balance sheet data for all periods presented 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, 2014 and 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 reflect a higher U.S. federal corporate tax rate when compared to our 2018 and expected future financial results.

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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 report.

	Year Ended December 31,				
(in thousands, except per share amounts)	2014	2015	2016	2017	2018
Statement of operations data:					
Operating revenues and other:					
Natural gas sales	$ 1,301,349	1,039,892	1,260,750	1,769,284	2,287,939
NGLs sales	328,323	264,483	432,992	870,441	1,177,777
Oil sales	107,080	70,753	61,319	108,195	187,178
Gathering, compression, and water handling and treatment	22,075	22,000	12,961	12,720	21,344
Marketing	53,604	176,229	393,049	258,045	458,901
Commodity derivative fair value gains (losses)	868,201	2,381,501	(514,181)	658,283	(87,594)
Marketing derivative fair value gains (losses)	—	—	—	(21,394)	94,081
Gain on sale of assets	40,000	—	97,635	—	—
Total operating revenues and other	2,720,632	3,954,858	1,744,525	3,655,574	4,139,626
Operating expenses:					
Lease operating	29,341	36,011	50,090	89,057	136,153
Gathering, compression, processing, and transportation	461,413	659,361	882,838	1,095,639	1,339,358
Production and ad valorem taxes	87,918	78,325	66,588	94,521	126,474
Marketing	103,435	299,062	499,343	366,281	686,055
Exploration	27,893	3,846	6,862	8,538	4,958
Impairment of unproved properties	15,198	104,321	162,935	159,598	549,437
Impairment of gathering systems and facilities	—	—	—	23,431	9,658
Depletion, depreciation, and amortization	477,896	709,763	809,873	824,610	972,465
Accretion of asset retirement obligations	1,271	1,655	2,473	2,610	2,819
General and administrative (including $112,252, $97,877, $102,421, $103,445 and $70,413 of equity-based compensation expense in 2014, 2015, 2016, 2017, and 2018, respectively)	216,533	233,697	239,324	251,196	240,344
Contract termination and rig stacking	—	38,531	—	—	—
Total operating expenses	1,420,898	2,164,572	2,720,326	2,915,481	4,067,721
Operating income (loss)	1,299,734	1,790,286	(975,801)	740,093	71,905
Other Expenses:					

Equity in earnings of unconsolidated affiliate	—	—	485	20,194	40,280
Interest expense	(160,051)	(234,400)	(253,552)	(268,701)	(286,743)
Loss on early extinguishment of debt	(20,386)	—	(16,956)	(1,500)	—
Total other expenses	(180,437)	(234,400)	(270,023)	(250,007)	(246,463)
Income (loss) before income taxes and discontinued operations	1,119,297	1,555,886	(1,245,824)	490,086	(174,558)
Income tax (expense) benefit	(445,672)	(575,890)	496,376	295,051	128,857
Income (loss) from continuing operations	673,625	979,996	(749,448)	785,137	(45,701)
Discontinued operations:					
Income from results of operations and sale of discontinued operations, net of income tax	2,210	—	—	—	—
Net income (loss) and comprehensive income (loss) including noncontrolling interest	675,835	979,996	(749,448)	785,137	(45,701)
Net income and comprehensive income attributable to noncontrolling interest	2,248	38,632	99,368	170,067	351,816
Net income (loss) attributable to Antero Resources Corporation	$ 673,587	941,364	(848,816)	615,070	(397,517)
Earnings (loss) per common share:					
Continuing operations	$ 2.56	3.43	(2.88)	1.95	(1.26)
Discontinued operations	$ 0.01	—	—	—	—
Total	$ 2.57	3.43	(2.88)	1.95	(1.26)
Earnings (loss) per common share—assuming dilution:					
Continuing operations	$ 2.56	3.43	(2.88)	1.94	(1.26)
Discontinued operations	$ 0.01	—	—	—	—
Total	$ 2.57	3.43	(2.88)	1.94	(1.26)

(in thousands)	Year Ended December 31, 2014	2015	2016	2017	2018
Balance sheet data (at period end):					
Cash and cash equivalents	$ 245,979	23,473	31,610	28,441	—
Other current assets	1,006,181	1,224,763	370,977	804,646	806,613
Total current assets	1,252,160	1,248,236	402,587	833,087	806,613
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,060,936	1,996,081	2,331,173	2,266,673	1,767,600
Producing properties	6,515,221	8,211,106	9,549,671	11,096,462	12,705,672
Water handling and treatment systems	421,012	565,616	744,682	946,670	1,013,818
Gathering systems and facilities	1,197,239	1,502,396	1,723,768	2,050,490	2,470,708
Other property and equipment	37,687	46,415	41,231	57,429	65,842
	10,232,095	12,321,614	14,390,525	16,417,724	18,023,640
Less accumulated depletion, depreciation, and amortization	(879,643)	(1,589,372)	(2,363,778)	(3,182,171)	(4,153,725)
Property and equipment, net	9,352,452	10,732,242	12,026,747	13,235,553	13,869,915
Other assets	934,766	2,135,015	1,826,216	1,192,850	842,936
Total assets	$ 11,539,378	14,115,493	14,255,550	15,261,490	15,519,464
Current liabilities	$ 894,732	707,270	817,388	762,096	853,540
Long-term indebtedness	4,328,433	4,668,782	4,703,973	4,800,090	5,461,688
Other long-term liabilities	842,383	1,452,763	1,005,611	823,168	716,759
Total equity	5,473,830	7,286,678	7,728,578	8,876,136	8,487,477
Total liabilities and equity	$ 11,539,378	14,115,493	14,255,550	15,261,490	15,519,464
Other financial data:					
Net cash provided by operating activities	$ 998,263	1,015,812	1,241,256	2,006,291	2,081,987
Net cash used in investing activities	$ (4,089,650)	(2,298,159)	(2,395,138)	(2,461,630)	(2,350,724)
Net cash provided by financing activities	$ 3,319,879	1,059,841	1,162,019	452,170	240,296
Capital expenditures	$ 4,086,568	2,347,909	2,495,429	2,216,753	2,210,586
Adjusted EBITDAX	$ 1,164,015	1,221,422	1,536,144	1,459,571	2,037,382

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income or loss from continuing operations, 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, impairment, depletion, depreciation, amortization, and accretion, exploration expense, franchise taxes, equity-based compensation, gain or loss on early extinguishment of debt, gain or loss on sale of assets, and contract termination and rig stacking costs. Adjusted EBITDAX also includes distributions from unconsolidated affiliates and excludes equity in earnings or losses of unconsolidated affiliates.

"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, 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 a company's 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, franchise 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 a company's 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 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. Consolidated EBITDAX, as defined under the Credit Facility, is used by our lenders pursuant to covenants under the Credit Facility and the indentures governing our senior notes.

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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) from continuing operations, including noncontrolling interest, to Adjusted EBITDAX from continuing operations, a reconciliation of our net income from discontinued operations to Adjusted EBITDAX from discontinued operations, 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:

	Year ended December 31,				
(in thousands)	2014	2015	2016	2017	2018
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 673,587	941,364	(848,816)	615,070	(397,517)
Net income and comprehensive income attributable to noncontrolling interests	38	38,632	99,368	170,067	351,816
Commodity derivative fair value (gains) losses (1)	(868,201)	(2,381,501)	514,181	(658,283)	87,594
Gains on settled commodity derivatives (1)	135,784	856,572	1,003,083	213,940	243,112
Marketing derivative fair value (gains) losses (1)	—	—	—	21,394	(94,081)
Gains on settled marketing derivatives (1)	—	—	—	—	72,687
Gain on sale of assets	(40,000)	—	(97,635)	—	—
Interest expense	160,051	234,400	253,552	268,701	286,743
Loss on early extinguishment of debt	20,386	—	16,956	1,500	—
Income tax expense (benefit)	445,672	575,890	(496,376)	(295,051)	(128,857)
Depletion, depreciation, amortization, and accretion	479,167	711,418	812,346	827,220	975,284
Impairment of unproved properties	15,198	104,321	162,935	159,598	549,437
Impairment of gathering systems and facilities	—	—	—	23,431	9,658
Exploration expense	27,893	3,846	6,862	8,538	4,958
Equity-based compensation expense	112,252	97,877	102,421	103,445	70,413
Equity in earnings of unconsolidated affiliate	—	—	(485)	(20,194)	(40,280)
Distributions from unconsolidated affiliates	—	—	7,702	20,195	46,415
State franchise taxes	2,188	72	50	—	—
	—	38,531	—	—	—

Contract termination and rig stacking					
Adjusted EBITDAX from continuing operations	1,164,015	1,221,422	1,536,144	1,459,571	2,037,382
Net income from discontinued operations	2,210	—	—	—	—
Gain on sale of assets	(3,564)	—	—	—	—
Income tax expense	1,354	—	—	—	—
Adjusted EBITDAX from discontinued operations	—	—	—	—	—
Total Adjusted EBITDAX	1,164,015	1,221,422	1,536,144	1,459,571	2,037,382
Interest expense	(160,051)	(234,400)	(253,552)	(268,701)	(286,743)
Exploration expense	(27,893)	(3,846)	(6,862)	(8,538)	(4,958)
Changes in current assets and liabilities	17,947	39,498	(32,920)	76,035	(25,423)
State franchise taxes	(2,188)	(72)	(50)	—	—
Proceeds from derivative monetizations	—	—	—	749,906	370,365
Premium paid on derivative contracts	—	—	—	—	(13,318)
Other non-cash items	6,433	(6,790)	(1,504)	(1,982)	4,682
Net cash provided by operating activities	$ 998,263	1,015,812	1,241,256	2,006,291	2,081,987

(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 which settled during the period. The adjustments do not include proceeds from derivatives monetization.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations— Stand-Alone Exploration and Production Information" for disclosure of Stand-Alone financial information.

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

Our Company

Antero Resources Corporation is 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, 2018, we held approximately 486,000 net acres in the southwestern core of the Marcellus Shale and approximately 125,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 209,000 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 249,000 net acres of our Marcellus Shale leasehold that may be prospective for the dry gas Utica Shale.

As of December 31, 2018, our estimated proved reserves were approximately 18.0 Tcfe, consisting of 11.4 Tcf of natural gas, 554 MMBbl of ethane, 498 MMBbl of C3+ NGLs, and 46 MMBbl of oil. This represents a 4% increase from December 31, 2017. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2018, we had approximately 3,734 potential horizontal well locations on our existing leasehold acreage which 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) gathering and processing; (iii) water handling and treatment; and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States.

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 2018, our production revenues were comprised of approximately 63% from the sale of natural gas and 37% 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 fixed price natural gas, NGLs, and oil swap contracts in which we receive or pay the difference between a fixed price and the variable market price received, basis swap contracts which hedge the difference between the New York Mercantile Exchange ("NYMEX") index price and a local index price and collar agreements that set a floor and ceiling price. At the end of each accounting period, we estimate the fair value of these swaps and collars 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.

Substantially all revenues from our gathering and processing and water handling and treatment operations are derived from intersegment transactions for services Antero Midstream provides to our exploration and production operations. The portion of such fees shown in our consolidated financial statements represent amounts charged to outside working interest owners in Antero-operated wells, as well as fees charged to other third parties for usage of Antero Midstream's gathering and compression systems or water handling and treatment services provided by Antero Midstream.

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.

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 operate and maintain our low- and high-pressure gathering and compression systems owned and operated by Antero Midstream, as well as fees paid to 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, 2016, 2017 and 2018.
· Impairment of unproved and proved properties. These costs include unproved property impairment and costs associated with lease expirations. We would also record impairment charges for proved properties if the carrying values were to exceed estimated future net cash flows and the fair values of the properties. We did not record any impairment for proved properties during the years ended December 31, 2016, 2017 and 2018.
· Depletion, depreciation, and amortization. Depletion, depreciation, and amortization, or 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. Gathering pipelines and compressor stations are depreciated over a 50 year useful life. Fresh water delivery systems are depreciated over a 5 to 20 year useful life. Specifically, we estimate a useful

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life of 5 years for our surface pipelines and equipment, 10 years for our above ground storage tanks, and 20 years for our permanent buried water pipeline systems.

· 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 included elsewhere in this report).

· Interest expense. We finance a portion of our capital expenditures, working capital requirements, and acquisitions with borrowings under our revolving credit facilities, which have variable rates 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, 2018, we had a fixed interest rate of 5.375% on our senior notes due 2021 having a principal balance of $1 billion, a fixed interest rate of 5.125% on our senior notes due 2022 having a principal balance of $1.1 billion, a fixed interest rate of 5.625% on our senior notes due 2023 having a principal balance of $750 million, and a fixed interest rate of 5.00% on our senior notes due 2025 having a principal balance of $600 million. Additionally, Antero Midstream had a fixed interest rate of 5.375% on its senior notes due 2024 having a principal balance of $650 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, 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 net operating loss carryforwards. At December 31, 2018, we had approximately $3.0 billion of U.S. federal net operating loss carryforwards (NOLs) that expire at various dates from 2025 through 2038, and approximately $2.3 billion of state NOLs that expire at various dates from 2019 through 2038. We recorded valuation allowances for deferred tax assets at December 31, 2018 of approximately $45 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. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for a discussion of the impact of the Tax Cuts and Jobs Act of 2017 on our deferred tax position and income tax expense.

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Results of Operations

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

The operating results of the Company's reportable segments were as follows for the years ended December 31, 2017 and 2018 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2017:						
Operating revenues 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
Gathering, compression, and water handling and treatment	—	396,466	376,031	—	(759,777)	12,720
Marketing	—	—	—	258,045	—	258,045
Commodity derivative fair value gains (losses)	658,283	—	—	(21,394)	—	636,889
Other income	16,667	—	—	—	(16,667)	—
Total	$ 3,423,561	396,466	376,031	236,651	(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	104	3,585	—	—	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
Accretion of asset retirement obligations	2,610	—	—	—	—	2,610
Depletion, depreciation, and amortization	704,152	87,268	33,190	—	—	824,610
	118,991	20,607	10,922	—	(2,769)	147,751

General and administrative (excluding equity-based compensation)						
Equity-based compensation	76,162	19,730	7,553	—	—	103,445
Change in fair value of contingent acquisition consideration	—	—	13,476	—	(13,476)	—
Total	2,695,770	190,287	258,428	366,281	(595,285)	2,915,481
Operating income (loss)	$ 727,791	206,179	117,603	(129,630)	(181,850)	740,093
Equity in earnings of unconsolidated affiliates	$ —	20,194	—	—	—	20,194

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	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2018:						
Operating revenues 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	—	520,566	507,373	—	(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	521,149	507,373	552,982	(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	48,998	552	—	(503,090)	1,339,358
Production and ad valorem taxes	122,305	258	3,911	—	—	126,474
Marketing	—	—	—	686,055	—	686,055
Exploration	4,958	—	—	—	—	4,958
Impairment of unproved properties	549,437	—	—	—	—	549,437
Impairment of gathering systems and facilities	—	9,658	—	—	—	9,658
Accretion of asset retirement obligations	2,684	—	135	—	—	2,819
Depletion, depreciation, and amortization	841,645	84,057	46,763	—	—	972,465
General and administrative (excluding equity-based compensation)	131,964	30,091	10,465	—	(2,590)	169,930
Equity-based compensation	49,341	16,518	4,555	—	—	70,414
	—	—	(93,019)	—	93,019	—

Change in fair value of contingent acquisition consideration						
Total	3,637,466	189,580	236,066	686,055	(681,446)	4,067,721
Operating income (loss)	$ (159,638)	331,569	271,307	(133,073)	(238,260)	71,905
Equity in earnings of unconsolidated affiliates	$ —	40,280	—	—	—	40,280

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Exploration and Production Segment Results for the Year Ended December 31, 2017 Compared to the Year Ended December 31, 2018

The following table sets forth selected operating data of the exploration and production segment for the year ended December 31, 2017 compared to the year ended December 31, 2018:

(Exploration and Production segment)	Year Ended December 31, 2017	2018	Amount of Increase (Decrease)	Percent Change
Production data:				
Natural gas (Bcf)	591	710	119	20 %
C2 Ethane (MBbl)	10,539	14,221	3,682	35 %
C3+ NGLs (MBbl)	25,507	28,913	3,406	13 %
Oil (MBbl)	2,451	3,265	814	33 %
Combined (Bcfe)	822	989	167	20 %
Daily combined production (MMcfe/d)	2,253	2,709	456	20 %
Average prices before effects of derivative settlements (1):				
Natural gas (per Mcf)	$ 2.99	$ 3.22	$ 0.23	8 %
C2 Ethane (per Bbl)	$ 8.83	$ 12.14	$ 3.31	37 %
C3+ NGLs (per Bbl)	$ 30.48	$ 34.76	$ 4.28	14 %
Oil (per Bbl)	$ 44.14	$ 57.34	$ 13.20	30 %
Weighted Average Combined (per Mcfe)	$ 3.34	$ 3.69	$ 0.35	10 %
Average realized prices after effects of derivative settlements (1):				
Natural gas (per Mcf)	$ 3.61	$ 3.65	$ 0.04	1 %
C2 Ethane (per Bbl)	$ 9.04	$ 12.14	$ 3.10	34 %
C3+ NGLs (per Bbl)	$ 24.27	$ 33.25	$ 8.98	37 %
Oil (per Bbl)	$ 45.85	$ 52.11	$ 6.26	14 %
Weighted Average Combined (per Mcfe)	$ 3.60	$ 3.94	$ 0.34	9 %
Average Costs (per Mcfe):				
Lease operating	$ 0.11	$ 0.14	$ 0.03	27 %
Gathering, compression, processing, and transportation	$ 1.75	$ 1.81	$ 0.06	3 %
Production and ad valorem taxes	$ 0.11	$ 0.12	$ 0.01	9 %
Depletion, depreciation, amortization, and accretion	$ 0.86	$ 0.85	$ (0.01)	(1) %
General and administrative (excluding equity-based compensation)	$ 0.14	$ 0.13	$ (0.01)	(7) %

(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.

Natural gas sales. Revenues from production of natural gas increased from $1.8 billion for the year ended December 31, 2017 to $2.3 billion for the year ended December 31, 2018, an increase of $518 million, or 29%. Increased natural gas production volumes accounted for an approximate $355 million increase in year-over-year product natural gas 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 $163 million increase in year-over-year product revenues (calculated as the change in the year-to-year average price times current year production volumes).

NGLs sales. Revenues from production of NGLs increased from $870 million for the year ended December 31, 2017 to $1.2 billion for the year ended December 31, 2018, an increase of $307 million, or 35%. Increased NGLs production volumes accounted for an approximate $136 million increase in year-over-year product NGLs 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 $171 million increase 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 increased from $108 million for the year ended December 31, 2017 to $187 million for the year ended December 31, 2018, an increase of $79 million, or 73% due to increases in production and prices.

During the year ended December 31, 2018, our natural gas prices and revenues were negatively affected by contractual issues with certain of our customers. For more information on these disputes, please see Note 14 to the consolidated financial statements or "Item 3. Legal Proceedings" included elsewhere in this Annual Report on Form 10-K.

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, 2017 and 2018, our commodity hedges resulted in derivative fair value gains (losses) of $658 million and $(88) million, respectively. The commodity derivative fair value gains (losses) included $214 million and $243 million of gains on cash settled derivatives for the years ended December 31, 2017 and 2018, respectively. Commodity derivative fair value gains (losses) for the years ended December 31, 2017 and 2018 also include proceeds of $750 million and $370 million, respectively, related to derivatives which were monetized prior to their contractual settlement dates. See "Item 1. Business and Properties—2018 and Recent Developments and Highlights—Delevering Activities" for further discussion.

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.

Other income (expense). Other income (expense) decreased from income of $17 million for the year ended December 31, 2017 to expense of $87 million for the year ended December 31, 2018. Other income (expense) primarily relates to decreases in the fair value of our exploration and production segment's contingent acquisition consideration that was received in connection with Antero's sale of its water handling and treatment assets to Antero Midstream in 2015. In conjunction with the acquisition of the water handling and treatment assets, Antero Midstream agreed to pay Antero (a) $125 million in cash if Antero Midstream delivers 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. The contingent acquisition consideration asset is recorded at its discounted net present value of the payout to be received by Antero, and is re-measured each period end. As a result of the decline in commodity prices in November 2018, the company's 2019 budget and forecasted water usage for these periods was reduced. As of December 31, 2018, Antero Midstream has delivered 128 million of the 176 million barrels and we expect to receive the entire amount of the contingent consideration for the 176 million barrels or more fresh water delivered during the period between January 1, 2017 and December 31, 2019, but Antero Midstream has delivered 71 million of the 219 million barrels and we do not expect Antero Midstream to deliver 219 million barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. Accordingly, the fair value of the contingent acquisition consideration was reduced by $106 million in 2018. The fair value measurement is based on significant inputs not observable in the market and thus represents a Level 3 measurement within the fair value hierarchy. The fair value of the contingent consideration associated with future milestone payments was based on the risk adjusted present value of the contingent consideration payout. Other income (expense) is eliminated upon consolidation.

Lease operating expense. Lease operating expense increased from $94 million for the year ended December 31, 2017 to $142 million for the year ended December 31, 2018, an increase of 52%. This increase is partly due to a 20% increase in production. On a per unit basis, lease operating expenses increased from $0.11 per Mcfe for the year ended December 31, 2017 to $0.14 per Mcfe for the year ended December 31, 2018. The increase in lease operating expenses on a per Mcfe basis is primarily due to the increase in the volume of produced water to be treated or disposed of due to an increase in water used in our advanced well completions.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $1.4 billion for the year ended December 31, 2017 to $1.8 billion for the year ended December 31, 2018. This is primarily a result of the increase in production. On a per Mcfe basis, total gathering, compression, processing, and transportation expenses increased from $1.75 per Mcfe for the year ended December 31, 2017 to $1.81 per Mcfe for the year ended December 31, 2018. Transportation expenses increased due to the Rover Pipeline that was placed in service in late 2017, which has higher per-unit transportation costs than our 2017 transportation portfolio, but in turn results in higher realized prices for our natural gas production. The transportation portfolio for 2018 is higher than in 2017 primarily because it includes a full year of the Rover Pipeline. In addition, our fees paid to Antero Midstream increased as our production growth required the use of more compression. This increase was partially offset by decreases in processing costs on a per Mcfe basis.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $91 million for the year ended December 31, 2017 to $122 million for the year ended December 31, 2018 primarily as a result of an increase in production revenues. On a per Mcfe basis, production and ad valorem taxes increased from $0.11 per Mcfe for the year ended December 31,

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2017 to $0.12 per Mcfe for the year ended December 31, 2018. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues remained relatively constant at 3.3% for the years ended December 31, 2017 and 2018.

Exploration expense. Exploration expense representing expenses incurred for unsuccessful lease acquisition efforts decreased from $9 million for the year ended December 31, 2017 to $5 million for the year ended December 31, 2018 as leasing activities declined.

Impairment of unproved properties. Impairment of unproved properties increased from $160 million for the year ended December 31, 2017 to $549 million for the year ended December 31, 2018. The increase was primarily due to the impairment of acreage in the Utica Shale expiring in the next 12 months outside of our primary area of development. 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.

Depletion, depreciation, and amortization expense ("DD&A"). DD&A expense increased from $704 million for the year ended December 31, 2017 to $842 million for the year ended December 31, 2018, primarily due to increased production. DD&A per Mcfe decreased from $0.86 per Mcfe during the year ended December 31, 2017 to $0.85 per Mcfe during the year ended December 31, 2018.

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 exceeded the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we would 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. As estimated future net cash flows were higher than the carrying values of our proved properties at December 31, 2018, we did not further evaluate our proved properties for impairment.

General and administrative expense. General and administrative expense (excluding equity-based compensation expense) increased from $119 million for the year ended December 31, 2017 to $132 million for the year ended December 31, 2018, primarily due to increases in employee related expenses as well as legal and other expenses related to the proposed simplification transaction. On a per unit basis, general and administrative expense excluding equity-based compensation decreased by 7%, from $0.14 per Mcfe during the year ended December 31, 2017 to $0.13 per Mcfe during the year ended December 31, 2018 as the increase in expenses from 2017 to 2018 was offset by a 20% increase in production. We had 593 employees as of December 31, 2017 and 623 employees as of December 31, 2018.

Equity-based compensation expense. Noncash equity-based compensation expense decreased from $76 million for the year ended December 31, 2017 to $49 million for the year ended December 31, 2018 as a result of equity award forfeitures, as well as a decrease in the total value of awards granted to officers and employees in 2018 as compared to 2017. When an equity award is forfeited, expense previously recognized for the award is reversed. See Note 9 to the unaudited consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Discussion of Gathering and Processing, Water Handling and Treatment, and Marketing Segment Results for the Year Ended December 31, 2017 Compared to the Year Ended December 31, 2018

Gathering and Processing. Revenue for the gathering and processing segment increased from $396 million for the year ended December 31, 2017 to $521 million for the year ended December 31, 2018, an increase of $125 million, or

32%. Gathering revenues increased by $86 million from the prior year period and compression revenues increased by $39 million as additional wells on production increased throughput volumes. Total operating expenses related to the gathering and processing segment remained relatively constant at $190 million for the years ended December 31, 2017 and 2018. Gathering, compression, processing and transportation expense and general and administrative expense (excluding equity-based compensation) increased from 2017 to 2018, which was offset by the lower impairment of gathering systems and facilities recorded in 2018 as compared to 2017.

Antero Midstream has two investments accounted for under the equity method: a 15% interest in a regional gathering pipeline purchased in May 2016, and a 50% interest in the Joint Venture with MarkWest entered into in February 2017. Equity in earnings of unconsolidated affiliates of $20 million and $40 million for the years ended December 31, 2017 and 2018, respectively, represents the portion of the net income from these investments which was allocated to Antero Midstream based on its equity interests. The increase was due to the commencement of operations by two additional processing plants owned by the Joint Venture.

Water Handling and Treatment. Revenue for the water handling and treatment segment increased from $376 million for the year ended December 31, 2017 to $507 million for the year ended December 31, 2018, an increase of $131 million or 35%. The

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increase was due to an increase in the number of well completions during 2018 as compared to 2017, as well as an increase in other fluid handling services as a result of the increase in the amount of water used. The volume of water delivered through the systems increased from 55.9 MMBbls for the year ended December 31, 2017 to 71.2 MMBbls for the year ended December 31, 2018. Operating expenses for the water handling and treatment segment decreased from $258 million for the year ended December 31, 2017 to $236 million for the year ended December 31, 2018. The decrease was due to a change in fair value of contingent acquisition consideration which more than offset the increase from other fluid handling services.

Antero Midstream's wastewater treatment facility was placed in service in 2018, but has not yet had a significant impact on the financial results of the water handling and treatment segment as a result of delays in reaching designed capacity under the terms of the agreement with the construction contractor. Due to these delays, Antero Midstream has and continues to accrue for liquidated damages from the vendor. At December 31, 2018, Antero Midstream had accrued $21 million for liquidated damages as a current asset and reduction in cost of the facility.

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 $237 million and $553 million and expenses of $366 million and $686 million for the years ended December 31, 2017 and 2018, 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 $96 million and $171 million for the year ended December 31, 2017 and 2018, respectively, which increased due to the Rover Pipeline that was placed in service in late 2017. Additionally, the marketing segment recorded a fair value loss of $21 million and gain of $94 million in the years ended December 31, 2017 and 2018, respectively, related to several natural gas purchase and sales contracts which were determined to be derivative instruments. See Note 11 to the consolidated financial statements included elsewhere in this Annual Report on Form 10-K for more information on these marketing derivative fair value gains (losses).

Operating losses on our marketing activities were $130 million and $133 million, or $0.13 per Mcfe and $0.23 per Mcfe, for the years ended December 31, 2017 and 2018, respectively.

Based on current projected 2019 annual production guidance, we estimate that we could incur annual net marketing costs of $0.175 per Mcfe to $0.225 per Mcfe in 2019 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. Our net marketing expense could increase in years subsequent to 2019 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 2019 assumes production growth and higher utilization of our transportation capacity.

Discussion of Items Not Allocated to Segments for the Year Ended December 31, 2017 Compared to the Year Ended December 31, 2018

Interest expense. Interest expense increased from $269 million for the year ended December 31, 2017 to $287 million for the year ended December 31, 2018 due to increased interest rates on Credit Facility borrowings and increased borrowings outstanding during 2018. Interest expense includes approximately $12 million and $13 million of non-cash amortization of deferred financing costs for the years ended December 31, 2017 and 2018, respectively.

Income tax benefit. Income tax benefit decreased from $295 million for the year ended December 31, 2017 to $129 million for the year ended December 31, 2018. The decrease was primarily due to the impact on 2017 of 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 of $428 million in 2017 primarily due to the remeasurement of our net deferred taxes liability for the reduction in the U.S. statutory rate from 35% to 21%. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for information regarding the impact of the Tax Cuts and Jobs Act on our income tax provision for the year ended December 31, 2017. For the year ended December 31, 2018, the Company's overall effective tax rate was different than the statutory rate of 21% primarily due to the effects of noncontrolling interests, state tax rates, and permanent differences on vested equity compensation awards.

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At December 31, 2018, we had approximately $3.0 billion of NOLs for U.S. federal income tax purposes that expire at various dates from 2025 through 2038 and approximately $2.3 billion of state NOLs that expire at various dates from 2019 through 2038. Future interpretations relating to the passage of the Tax Cuts and Jobs Act which 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, 2016 Compared to Year Ended December 31, 2017

The operating results of the Company's reportable segments were as follows for the years ended December 31, 2016 and 2017 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2016:						
Operating revenues and other:						
Natural gas sales	$ 1,260,750	—	—	—	—	1,260,750
Natural gas liquids sales	432,992	—	—	—	—	432,992
Oil sales	61,319	—	—	—	—	61,319
Gathering, compression, and water handling and treatment	—	304,085	282,267	—	(573,391)	12,961
Marketing	—	—	—	393,049	—	393,049
Commodity derivative fair value losses	(514,181)	—	—	—	—	(514,181)
Gain on sale of assets	93,776	3,859	—	—	—	97,635
Other income	18,324	—	—	—	(18,324)	—
Total	$ 1,352,980	307,944	282,267	393,049	(591,715)	1,744,525
Operating expenses:						
Lease operating	$ 50,651	—	136,386	—	(136,947)	50,090
Gathering, compression, processing, and transportation	1,146,221	28,098	—	—	(291,481)	882,838
Production and ad valorem taxes	69,485	(809)	(2,088)	—	—	66,588
Marketing	—	—	—	499,343	—	499,343
Exploration	6,862	—	—	—	—	6,862
Impairment of unproved properties	162,935	—	—	—	—	162,935
Accretion of asset retirement obligations	2,473	—	—	—	—	2,473
Depletion, depreciation, and amortization	709,127	70,847	29,899	—	—	809,873

General and administrative (excluding equity-based compensation)	110,300	20,118	7,996	—	(1,511)	136,903
Equity-based compensation	76,372	19,714	6,335	—	—	102,421
Change in fair value of contingent acquisition consideration	—	—	16,489	—	(16,489)	—
Total	2,334,426	137,968	195,017	499,343	(446,428)	2,720,326
Operating income (loss)	$ (981,446)	169,976	87,250	(106,294)	(145,287)	(975,801)
Equity in earnings of unconsolidated affiliates	$ —	485	—	—	—	485

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	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2017:						
Operating revenues 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
Gathering, compression, and water handling and treatment	—	396,466	376,031	—	(759,777)	12,720
Marketing	—	—	—	258,045	—	258,045
Commodity derivative fair value gains (losses)	658,283	—	—	(21,394)	—	636,889
Other income	16,667	—	—	—	(16,667)	—
Total	$ 3,423,561	396,466	376,031	236,651	(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	104	3,585	—	—	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
Accretion of asset retirement obligations	2,610	—	—	—	—	2,610
Depletion, depreciation, and amortization	704,152	87,268	33,190	—	—	824,610
General and administrative (excluding equity-based compensation)	118,991	20,607	10,922	—	(2,769)	147,751
Equity-based compensation	76,162	19,730	7,553	—	—	103,445

Change in fair value of contingent acquisition consideration	—	—	13,476	—	(13,476)	—
Total	2,695,770	190,287	258,428	366,281	(595,285)	2,915,481
Operating income (loss)	$ 727,791	206,179	117,603	(129,630)	(181,850)	740,093
Equity in earnings of unconsolidated affiliates	$ —	20,194	—	—	—	20,194

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Exploration and Production Segment Results for the Year Ended December 31, 2016 Compared to the Year Ended December 31, 2017

The following table sets forth selected operating data of the exploration and production segment for the year ended December 31, 2016 compared to the year ended December 31, 2017:

	Year Ended December 31, 2016	2017	Amount of Increase (Decrease)	Percent Change	
Production data:					
Natural gas (Bcf)	505	591	86	17	%
C2 Ethane (MBbl)	6,396	10,539	4,143	65	%
C3+ NGLs (MBbl)	20,279	25,507	5,228	26	%
Oil (MBbl)	1,873	2,451	578	31	%
Combined (Bcfe)	676	822	146	22	%
Daily combined production (MMcfe/d)	1,847	2,253	406	22	%
Average prices before effects of derivative settlements (1):					
Natural gas (per Mcf)	$ 2.50	$ 2.99	$ 0.49	20	%
C2 Ethane (per Bbl)	$ 8.28	$ 8.83	$ 0.55	7	%
C3+ NGLs (per Bbl)	$ 18.74	$ 30.48	$ 11.74	63	%
Oil (per Bbl)	$ 32.73	$ 44.14	$ 11.41	35	%
Weighted Average Combined (per Mcfe)	$ 2.60	$ 3.34	$ 0.74	28	%
Average realized prices after effects of derivative settlements (1):					
Natural gas (per Mcf)	$ 4.39	$ 3.61	$ (0.78)	(18)	%
C2 Ethane (per Bbl)	$ 8.28	$ 9.04	$ 0.76	9	%
C3+ NGLs (per Bbl)	$ 21.03	$ 24.27	$ 3.24	15	%
Oil (per Bbl)	$ 32.73	$ 45.85	$ 13.12	40	%
Weighted Average Combined (per Mcfe)	$ 4.08	$ 3.60	$ (0.48)	(12)	%
Average Costs (per Mcfe):					
Lease operating	$ 0.07	$ 0.11	$ 0.04	57	%
Gathering, compression, processing, and transportation	$ 1.70	$ 1.75	$ 0.05	3	%
Production and ad valorem taxes	$ 0.10	$ 0.11	$ 0.01	10	%
Marketing expense, net	$ 0.16	$ 0.13	$ (0.03)	(19)	%
Depletion, depreciation, amortization, and accretion	$ 1.05	$ 0.86	$ (0.19)	(18)	%
General and administrative (excluding equity-based compensation)	$ 0.16	$ 0.14	$ (0.02)	(13)	%

(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.

Natural gas sales. Revenues from production of natural gas increased from $1.3 billion for the year ended December 31, 2016 to $1.8 billion for the year ended December 31, 2017, an increase of $509 million, or 40%. Increased natural gas production volumes accounted for an approximate $215 million increase in year-over-year product natural gas 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 $294 million increase in year-over-year product revenues (calculated as the change in the year-to-year average price times current year production volumes).

NGLs sales. Revenues from production of NGLs increased from $433 million for the year ended December 31, 2016 to $870 million for the year ended December 31, 2017, an increase of $437 million, or 101%. Increased NGL production volumes accounted for an approximate $132 million increase in year-over-year product NGL 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 $305 million increase in year-over-year product revenues (calculated as the change in the year-to-year average price times current year production volumes). NGL production increased at a higher rate than gas production as a result of drilling more liquids rich wells.

Oil sales. Revenues from production of oil increased from $61 million for the year ended December 31, 2016 to $108 million for the year ended December 31, 2017, an increase of $47 million, or 76% due to increase in prices and production. Oil production increased at a higher rate than gas production as a result of drilling more liquids rich wells.

During the year ended December 31, 2017, our natural gas prices and revenues were negatively affected by contractual issues with certain of our customers. For more information on these disputes, please see Note 14 to the consolidated financial statements or "Item 3. Legal Proceedings" included elsewhere in this Annual Report on Form 10-K.

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, 2016 and 2017, our commodity hedges resulted in derivative fair value gains (losses) of $(514) million and $658 million, respectively. The commodity derivative fair value gains included $1.0 billion and $214 million of gains on cash settled derivatives for the years ended December 31, 2016 and 2017, respectively. Commodity derivative fair value gains (losses) for the year ended December 31, 2017 includes proceeds on cash settled derivatives of $750 million related to derivatives which 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.

Gain on sale of assets. In December 2016, we closed the sale of approximately 17,000 net acres primarily located in Washington and Westmoreland Counties, Pennsylvania. The acreage was outside of the Company's infrastructure build-out and was not expected to be developed in the near future. Included in the sale were two Antero operated producing wells and a gathering pipeline belonging to Antero Midstream. Total proceeds from the sale were $170 million. As a result of the sale, the Company recognized a gain on the sale of assets of $99 million for the year ended December 31, 2016, $95 million of which was attributable to the producing wells and undeveloped acreage. We also recognized net losses of approximately $1 million that were attributable to other asset sales during the year ended December 31, 2016, resulting in a net gain on sales of assets of $94 million for the exploration and production segment.

Other income. Other income decreased from $18 million for the year ended December 31, 2016 to $17 million for the year ended December 31, 2017. Other income primarily relates to increases in the fair value of our exploration and production segment's contingent acquisition consideration that was received in connection with Antero's sale of its water handling and treatment assets to Antero Midstream in 2015. In conjunction with the acquisition of the water handling and treatment assets, Antero Midstream agreed to pay Antero (a) $125 million in cash if Antero Midstream delivers 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. The contingent acquisition consideration asset is recorded at its discounted net present value of the payout to be received by Antero, and is re-measured each period end. As the net present value of the contingent acquisition consideration asset increases, we recognize income in the exploration and production segment for the change in value. Other income is eliminated upon consolidation.

Lease operating expense. Lease operating expense increased from $51 million for the year ended December 31, 2016 to $94 million for the year ended December 31, 2017, an increase of 85%. The increase is primarily a result of an increase in production and the number of producing wells. On a per Mcfe basis, lease operating expense increased from $0.07 per Mcfe for the year ended December 31, 2016 to $0.11 per Mcfe for the year ended December 31,

2017. The increase in lease operating expenses on a per Mcfe basis is due to an increase in produced water on new wells, which is attributable to an increase in the amount of water used in our advanced well completions.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $1.1 billion for the year ended December 31, 2016 to $1.4 billion for the year ended December 31, 2017. The increase in these expenses is a result of the increase in production and the related firm transportation, gathering, compression, and processing expenses. On a per Mcfe basis, total gathering, compression, processing, and transportation expenses increased by 3%, from $1.70 per Mcfe for the year ended December 31, 2016 to $1.75 per Mcfe for the year ended December 31, 2017, primarily due to increased utilization of Tennessee Gas Pipeline in 2017 which had higher per-unit transportation costs than our prior year's transportation portfolio, but in turn resulted in higher realized prices for our natural gas production. In addition, our fees paid to Antero Midstream increased as our production growth required the use of more compression.

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Production and ad valorem tax expense. Total production and ad valorem taxes increased from $69 million for the year ended December 31, 2016 to $91 million for the year ended December 31, 2017 as a result of an increase in production revenues. On a per-unit basis, production and ad valorem taxes increased from $0.10 per Mcfe for the year ended December 31, 2016, to $0.11 per Mcfe for the year ended December 31, 2017 as a result of increases in per-unit production revenues. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging decreased from 4.0% for the year ended December 31, 2016 to 3.3% for the year ended December 31, 2017 primarily attributable to the termination of a West Virginia production tax surcharge for workers' compensation funding on July 1, 2016.

Exploration expense. Exploration expense increased from $7 million for the year ended December 31, 2016 to $9 million for the year ended December 31, 2017. These amounts represent expenses incurred for unsuccessful lease acquisition efforts.

Impairment of unproved properties. Impairment of unproved properties decreased slightly from $163 million for the year ended December 31, 2016 to $160 million for the year ended December 31, 2017. 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, or future plans to develop the acreage.

Depletion, depreciation, and amortization expense ("DD&A"). DD&A expense decreased from $709 million for the year ended December 31, 2016 to $704 million for the year ended December 31, 2017, due to a 16% decrease in our depletion rate for proved properties (see below) which offset the 22% increase in production. DD&A per Mcfe decreased by 18%, from $1.05 per Mcfe during the year ended December 31, 2016 to $0.86 per Mcfe during the year ended December 31, 2017. This decrease was due to increases in our estimated recoverable reserves, due to improved well performance, and decreases in our per-unit development costs, which is due to well cost reductions and drilling and completion efficiencies that we have achieved over the last year.

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 exceeded the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we would 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. As estimated future net cash flows were higher than the carrying values of our proved properties at December 31, 2017, we did not further evaluate our proved properties for impairment.

General and administrative expense. General and administrative expense (excluding equity-based compensation expense) increased from $110 million for the year ended December 31, 2016 to $119 million for the year ended December 31, 2017, primarily due to increases in employee related expenses. On a per unit basis, general and administrative expense excluding equity-based compensation decreased by 13%, from $0.16 per Mcfe during the year ended December 31, 2016 to $0.14 per Mcfe during the year ended December 31, 2017, primarily due to our 22% increase in production. We had 528 employees as of December 31, 2016 and 593 employees as of December 31, 2017.

Equity-based compensation expense. Noncash equity-based compensation expense remained consistent at $76 million for the years ended December 31, 2016 and 2017. See Note 9 to the consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Discussion of Gathering and Processing, Water Handling and Treatment, and Marketing Segment Results for the Year Ended December 31, 2016 Compared to the Year Ended December 31, 2017

Gathering and Processing. Revenue for the gathering and processing segment increased from $308 million for the year ended December 31, 2016 to $396 million for the year ended December 31, 2017, an increase of $88 million, or 29%. Gathering revenues increased by $61 million from the prior year and compression revenues increased by $31 million as additional wells on production increased throughput volumes. Total operating expenses related to the gathering and processing segment increased from $138 million for the year ended December 31, 2016 to $190 million for the year ended December 31, 2017 primarily as a result of increases in direct operating and depreciation expenses due to a larger base of gathering and compression assets. Operating expenses of $190 million during the year ended December 31, 2017 included a $23 million impairment charge for the carrying value of property and equipment related to Antero Midstream's condensate gathering lines in Ohio which are no longer servicing Antero's production.

In May 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline. In February 2017, Antero Midstream formed the Joint Venture with MarkWest, which provides natural gas processing and fractionation services. Equity in earnings of unconsolidated affiliates of $0.5 million and $20 million for the years ended December 31, 2016 and 2017, respectively, represents the portion of the net income from these investments which is allocated to Antero Midstream based on its equity interests.

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The increase was due to a full year of investment income in the regional gathering pipeline during 2017, as opposed to eight months during 2016, and the commencement of operations of the Joint Venture in February 2017.

Water Handling and Treatment. Revenue for the water handling and treatment segment increased from $282 million for the year ended December 31, 2016 to $376 million for the year ended December 31, 2017, an increase of $94 million or 33%. The increase was due to an increase in the volume of water used per well in our advanced completions during 2017 as compared to 2016, as well as an increase in other fluid handling services. The volume of water delivered through the water distribution systems increased from 45.1 MMBbls for the year ended December 31, 2016 to 55.9 MMBbls for the year ended December 31, 2017. Operating expenses for the water handling and treatment segment increased from $195 million for the year ended December 31, 2016 to $258 million for the year ended December 31, 2017, primarily due to the increase in other fluid handling services.

Marketing. Where permitted, 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 of $393 million and $258 million and expenses of $499 million and $366 million for the years ended December 31, 2016 and 2017, respectively, related to these activities.

Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This included firm transportation costs of $114 million and $96 million for the years ended December 31, 2016 and 2017, respectively, related to unutilized excess capacity which decreased due to the assumption of certain unutilized firm transportation capacity by a third party beginning July 1, 2016. Additionally, the marketing segment incurred a fair value loss of $21 million related to several natural gas purchase and sales contracts during the year ended December 31, 2017 which were determined to be derivative instruments. See Note 11 to the consolidated financial statements included elsewhere in this Annual Report on Form 10-K for more information on these contracts.

Net losses on our marketing activities were $106 million and $130 million, or $0.16 per Mcfe and $0.13 per Mcfe, for the years ended December 31, 2016 and 2017, respectively.

Discussion of Items Not Allocated to Segments for the Year Ended December 31, 2016 Compared to the Year Ended December 31, 2017

Interest expense. Interest expense increased from $254 million for the year ended December 31, 2016 to $269 million for the year ended December 31, 2017, primarily due to Antero Midstream's issuance of its 5.375% senior notes due 2024 in September 2016 and increased average balances outstanding under our revolving credit facilities. Interest expense includes approximately $12 million of non-cash amortization of deferred financing costs for each of the years ended December 31, 2016 and 2017.

Loss on extinguishment of debt. Loss on extinguishment of debt decreased from $17 million for the year ended December 31, 2016 to $1.5 million for the year ended December 31, 2017. In 2016, we satisfied and discharged our obligations with respect to our outstanding 6.00% senior notes due 2020, resulting in a loss on early redemption of $17 million. In October 2017, Antero and Antero Midstream both entered into amended and restated credit facilities. In conjunction with the retirement of the old facilities, we recorded a loss of $1.5 million on deferred financing costs associated with lenders who did not continue in the new facility.

Income tax benefit. Income tax benefit decreased from $496 million for the year ended December 31, 2016 to $295 million for the year ended December 31, 2017. The decrease was primarily due to pre-tax income generated for financial reporting purposes for the year ended December 31, 2017, whereas we incurred a pre-tax loss for financial reporting purposes for the year ended December 31, 2016, partially offset by the impact of 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 of $428 million primarily due to the remeasurement of our net deferred taxes liability for the reduction in the U.S. statutory rate from 35% to 21%. See Note 12 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K for information regarding the impact of the Tax Cuts and Jobs Act on our income tax provision for the year ended December 31, 2017.

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Capital Resources and Liquidity

Our primary sources of liquidity have been through net cash provided by operating activities including proceeds from derivatives, borrowings under our revolving credit facilities, issuances of debt and equity securities, and asset sales. Our primary use of cash has been for the exploration, development, and acquisition of oil and natural gas properties, as well as for development of gathering and compression systems and facilities, and fresh water handling and wastewater treatment infrastructure. 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 corporate family credit ratings as issued by the credit rating agencies are BBB- from Fitch, BB+ from S&P and Ba2 from Moody's. 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, 2018, we had 3,734 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 $3.5 billion of development capital over the next five years in order to fully develop the properties associated with our proved reserves.

Based on strip pricing as of December 31, 2018, 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."

Antero's revolving credit facility has a borrowing base of $4.5 billion and current lender commitments of $2.5 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 2019. For a discussion of the risks of a decrease in the borrowing base under our revolving credit facility, see "Item 1A. Risk Factors—The borrowing base under our revolving credit facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs."

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 our revolving 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. Our revolving credit facility is funded by a syndicate of 24 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 our revolving credit facility. In addition to Antero's credit facility, Antero Midstream has a revolving credit facility that provides for lender commitments of $2.0 billion.

For the year ended December 31, 2018, our total consolidated capital expenditures were approximately $2.2 billion, including drilling and completion expenditures of $1.5 billion, leasehold additions of $172 million, gathering and compression expenditures of $444 million, water handling and treatment expenditures of $98 million, and other capital expenditures of $8 million. In response to recent oil and NGL price declines, we have reduced our consolidated capital budget for 2019 to $1.9 billion to $2.2 billion. Our budget includes: $1.1 billion to $1.25 billion for drilling and completion, $75 million to $100 million for leasehold expenditures, and $750 million to $800 million for capital expenditures by Antero Midstream, which includes $200 million for investments in unconsolidated affiliates. We do not budget for acquisitions. During 2019, we plan to operate an average of five drilling rigs and four completion crews and we plan to complete 115-125 horizontal wells in the Marcellus and Utica Shales in 2019. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Based on strip pricing as of December 31, 2018, we believe that funds from operating cash flows and available borrowings under the Credit Facility and Midstream Credit Facility, or capital market transactions, will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "—Debt Agreements and Contractual Obligations."

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Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2016, 2017, and 2018:

	Year Ended December 31,		
(in thousands)	2016	2017	2018
Net cash provided by operating activities	$ 1,241,256	2,006,291	2,081,987
Net cash used in investing activities	(2,395,138)	(2,461,630)	(2,350,724)
Net cash provided by financing activities	1,162,019	452,170	240,296
Net increase (decrease) in cash and cash equivalents	$ 8,137	(3,169)	(28,441)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities was $1.2 billion, $2.0 billion and $2.1 billion for the years ended December 31, 2016, 2017 and 2018, respectively. Cash flow from operations remained relatively unchanged from 2017 to 2018 as the increase in product revenues excluding hedges of $905 million was offset by a $380 million decrease in proceeds from derivative monetization of $750 million in 2017 compared to $370 million in 2018, as well as an increase in costs driven by increases in production. The $765 million increase in cash flows from operations from 2016 to 2017 was primarily a result of increases in total product revenues excluding hedges of $993 million offset by a $40 million decrease from $1.0 billion in 2016 to $964 million in 2017 of total cash flow realized from settled derivatives, as well as increased costs driven by increases in production.

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

During the years ended December 31, 2016, 2017, and 2018, we used cash flows in investing activities of $2.4 billion, $2.5 billion, and $2.4 billion, respectively, primarily as a result of our capital expenditures for drilling, development, acquisitions, and construction of midstream and water handling and treatment infrastructure and investments in joint ventures.

Cash flows used in investing activities decreased from $2.5 billion for the year ended December 31, 2017 to $2.4 billion for the year ended December 31, 2018, primarily due a $99 million decrease in investments in joint ventures by Antero Midstream from $235 million during the year ended December 31, 2017 to $136 million during the year ended December 31, 2018. Total capital expenditures for oil and gas properties during the year ended December 31, 2018, remained consistent with the year ended December 31, 2017 at $1.7 billion. Our capital expenditures on midstream assets stayed relatively unchanged as capital expenditures for water handling and treatment systems, decreased $97 million from $195 million for the year ended December 31, 2017 to $98 million for the year ended December 31, 2018, while our capital expenditures for gathering and compression systems increased $98 million from $346 million to $444 million.

Cash flows used in investing activities increased from $2.4 billion for the year ended December 31, 2016 to $2.5 billion for the year ended December 31, 2017. Total capital expenditures for oil and gas properties during the year ended December 31, 2018, decreased $412 million from $2.1 billion to $1.7 billion due to a reduction in number of wells drilled and completed as we responded to declining commodity prices. Our capital expenditures on midstream assets increased $121 million primarily due to the capital expenditures on the Clearwater wastewater treatment facility. Our investments in joint ventures increased $159 million as we entered into the joint venture agreement with MarkWest in early 2017. In 2017, proceeds from the sale of assets also decreased by $170 million.

In response to recent oil and NGL price declines, we have reduced our consolidated exploration and production capital budget for 2019 to $1.2 billion to $1.4 billion, which does not include the capital budget of $750 million to $800 million for Antero Midstream, our consolidated subsidiary. 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

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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, 2016, 2017, and 2018, net cash flows provided by financing activities were $1.2 billion, $452 million, and $240 million primarily as a result of capital market transactions and changes in long term debt.

Net cash flows provided by financing activities decreased from $452 million for the year ended December 31, 2017 to $240 million for the year ended December 31, 2018.

Net borrowings on our credit facilities increased from $90 million in 2017 to $660 million in 2018, whereas in 2017, $311 million was generated from the sale of Antero Midstream common units owned by Antero as well as $249 million through the issuance of new common units by Antero Midstream. This was partially offset by an increase of $115 million in distributions to noncontrolling interests in Antero Midstream from $152 million in 2017 to $267 million in 2018, 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.

Net cash provided by financing activities decreased from $1.2 billion in 2016 to $452 million in 2017. In 2016, Antero issued 36,493,000 new shares for proceeds of $1.0 billion. Proceeds raised through the issuance of new units of Antero Midstream and sale of units held by Antero increased $317 million from $243 million in 2016 compared to $560 million in 2017. In 2016, Antero issued $1.25 billion of new senior notes to repay existing senior notes of $525 million as well as the bank credit facility. Overall, net increase in long term debt was $48 million in 2016 compared to $90 million in 2017. Distributions to noncontrolling interests in Antero Midstream increased $77 million from $75 million in 2016 to $152 million in 2017.

Stand-Alone Exploration and Production Information

As explained in Note 17 to the Consolidated Financial Statements included elsewhere in this 2018 Annual Report on Form 10-K, each of the wholly-owned subsidiaries of Antero Resources Corporation has guaranteed Antero's senior notes. Antero Midstream and its subsidiaries do not guarantee Antero's senior notes or any of its other obligations. Note 17 to the Consolidated Financial Statements includes the condensed consolidating balance sheets, statements of operations and comprehensive income (loss), and statements of cash flows on a consolidating basis for Antero (the Parent) and Antero Midstream (Antero's non-guarantor subsidiaries). Antero (Parent) includes the assets, liabilities, results of operations, and cash flows for the exploration and production and marketing operations of the Company, including cash flows related to Antero's ownership of common units in Antero Midstream and Antero's stand-alone debt obligations not guaranteed by Antero Midstream.

We believe the Antero (Parent) information is useful to investors as a means to evaluate Antero's operations on a stand-alone basis and its ability to service its debt obligations that are not guaranteed by Antero Midstream or to incur additional debt. We believe that funds from stand-alone operating cash flows, available borrowings under the Credit Facility, and future capital market transactions by Antero, will be sufficient to meet Antero's cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. The following table presents

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selected financial information on a stand-alone basis for Antero (Parent) as of and for the years ended December 31, 2016, 2017 and 2018:

	Year Ended December 31,		
(in thousands)	2016	2017	2018
Statement of operations data:			
Revenue and other	$ 1,746,029	3,660,212	4,031,065
Operating expenses	2,834,654	3,062,947	4,328,798
Operating income (loss)	(1,088,625)	597,265	(297,733)
Interest expense and other	(256,567)	(277,246)	(228,641)
Income (loss) before income taxes	(1,345,192)	320,019	(526,374)
Provision for income tax benefit	496,376	295,051	128,857
Net income (loss) and comprehensive income (loss)	$ (848,816)	615,070	(397,517)
Balance sheet data:			
Current assets	$ 389,969	829,343	783,939
Property and equipment, net	10,008,154	10,989,795	11,503,388
Other assets	1,526,259	510,716	(231,667)
Total assets	$ 11,924,382	12,329,854	12,055,660
Current liabilities	$ 802,707	759,021	865,466
Long-term debt	3,854,059	3,604,090	3,829,541
Other long-term liabilities	1,004,991	822,758	708,678
Total equity	6,262,625	7,143,985	6,651,975
Total liabilities and equity	$ 11,924,382	12,329,854	12,055,660
Other financial data:			
Net cash provided by operating activities:	$ 1,105,238	1,836,322	1,822,855
Net cash used in investing activities	$ (2,052,200)	(1,856,041)	(1,923,384)
Net cash provided by financing activities	$ 947,940	22,229	80,451
Capital expenditures	$ 2,214,334	1,849,603	1,923,312
Stand-Alone Adjusted EBITDAX	$ 1,384,442	1,244,394	1,717,121

"Stand-Alone Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income or loss from continuing operations on a stand-alone basis for Antero (Parent) 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, impairment, depletion, depreciation, amortization, and accretion, exploration expense, franchise taxes, equity-based compensation, gain or loss on early extinguishment of debt, gain or loss on sale of assets, equity in earnings or loss of Antero Midstream, and gain or loss on changes in the fair value of contingent acquisition consideration. Stand-Alone Adjusted EBITDAX also includes distributions received from limited partner interests in Antero Midstream common units.

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

- is used by investors in the oil and natural gas industry to measure a company's 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 consolidated 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. EBITDAX, as defined

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under the Credit Facility, is used by our lenders pursuant to covenants under the Credit Facility and the indentures governing our senior notes, and is used as one of several evaluation metrics during the annual redetermination process for the Credit Facility.

There are significant limitations to using Stand-Alone Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect 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 presents a reconciliation of Antero's stand-alone net income (loss) to Stand-Alone Adjusted EBITDAX, and a reconciliation of Stand-Alone Adjusted EBITDAX to Antero's stand-alone net cash provided by operating activities per our condensed consolidating statements of cash flows (see Note 17 to our Consolidated Financial Statements), in each case, for the periods presented:

	Year Ended December 31,		
(in thousands)	2016	2017	2018
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (848,816)	615,070	(397,517)
Commodity derivative fair value (gains) losses (1)	514,181	(658,283)	87,594
Gains on settled commodity derivatives (1)	1,003,083	213,940	243,112
Marketing derivative fair value (gains) losses (1)	—	21,394	(94,081)
Gains (losses) on settled marketing derivatives (1)	—	—	72,687
Gain on sale of assets	(93,776)	—	—
Interest expense	232,455	232,331	224,977
Loss on early extinguishment of debt	16,956	1,205	—
Income tax benefit	(496,376)	(295,051)	(128,857)
Depletion, depreciation, amortization, and accretion	712,485	707,658	845,136
Impairment of unproved properties	162,935	159,598	549,437
Impairment of gathering systems and facilities	—	—	4,470
Exploration expense	6,862	8,538	4,958
Gain on change in fair value of contingent acquisition consideration	(16,489)	(13,476)	93,019
Equity-based compensation expense	76,372	76,162	49,341
Equity in loss of Antero Midstream Partners LP	7,156	43,710	3,664
Distributions from Antero Midstream Partners LP	107,364	131,598	159,181
State franchise taxes	50	—	—
Stand-Alone Adjusted EBITDAX	1,384,442	1,244,394	1,717,121
Interest expense	(232,455)	(232,331)	(224,977)
Exploration expense	(6,862)	(8,538)	(4,958)
Changes in current assets and liabilities	(36,519)	87,466	(26,059)
Proceeds from derivative monetizations	—	749,906	370,365
Premium paid on derivative contracts	—	—	(13,318)
Other non-cash items	(3,318)	(4,575)	4,681
Net cash provided by operating activities	$ 1,105,238	1,836,322	1,822,855

(1) The adjustments for the derivative gains and losses and gains on settled commodity and marketing derivatives have the effect of adjusting net income from operations for changes in the fair value of unsettled derivatives, which are recognized at the end of each accounting period. As a result, Stand-Alone Adjusted EBITDAX only reflects

derivatives which settled during the period, excluding proceeds from derivative monetizations.

Stand-Alone Adjusted EBITDAX. Stand-Alone Adjusted EBITDAX increased from $1.2 billion for the year ended December 31, 2017 to $1.7 billion for the year ended December 31, 2018, an increase of 38%. The increase in Adjusted EBITDAX and Stand-Alone Adjusted EBITDAX was primarily due to increases in our average realized price for liquids and increased production, net of increased costs related to higher production levels.

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Debt Agreements and Contractual Obligations

Antero Senior Secured Revolving Credit Facility. Antero's 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, 2018, the borrowing base was $4.5 billion and lender commitments were $2.5 billion. The next redetermination of the borrowing base is scheduled to occur by the end of April 2019. At December 31, 2018, we had $405 million of borrowings with a weighted average interest rate of 3.95% and $685 million of letters of credit outstanding under the Credit Facility. At December 31, 2017, we had $185 million of borrowings and $705 million of letters of credit outstanding under the Credit Facility, with a weighted average interest rate of 2.96%. 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, unless such series of senior notes is refinanced.

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 and 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.

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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, 2017 and December 31, 2018. The actual borrowing capacity available to us may be limited by the financial ratio covenants. At December 31, 2018, our current ratio was 4.57 to 1.0 (based on the $4.5 billion borrowing base under the Credit Facility) and our interest coverage ratio was 9.23 to 1.0.

Midstream Credit Facility. Antero Midstream has a secured revolving credit facility among Antero Midstream, certain lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, and swing line lender. The Midstream Credit Facility provides for lender commitments of $2.0 billion and for a letter of credit sublimit of $150 million. At December 31, 2018, Antero Midstream had $990 million of borrowings with a weighted average interest rate of 3.75% and no letters of credit outstanding under the Midstream Credit Facility. At December 31, 2017, Antero Midstream had a total outstanding balance under the Midstream Credit Facility of $555 million, with a weighted average interest rate of 2.81%. The Midstream Credit Facility matures on October 26, 2022.

Under the Midstream Credit Facility, "Investment Grade Period" is a period that, as long as no event of default has occurred and the Partnership is in pro forma compliance with the financial covenants under the Midstream Credit Facility, commences when the Partnership elects to give notice to the Administrative Agent that the Partnership has received at least one of either (i) a BBB- or better rating from Standard and Poor's or (ii) a Baa3 or better from Moody's (provided that the non-investment grade rating from the other rating agency is at least either Ba1 if Moody's or BB+ if Standard and Poor's (an "Investment Grade Rating")). An Investment Grade Period can end at the Partnership's election.

Antero Midstream has a choice of borrowing in Eurodollars or at the base rate. Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable (i) with respect to base rate loans, quarterly and (ii) with respect to Eurodollar loans, the last day of each Interest Period (as defined below); provided that if any Interest Period for a Eurodollar loan exceeds three months, interest will be payable on the respective dates that fall every three months after the beginning of such Interest Period. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or, if available to the lenders, twelve months (the "Interest Period") plus an applicable margin ranging from (i) 125 to 225 basis points during any period that is not an Investment Grade Period, depending on the leverage ratio then in effect and (ii) 112.5 to 200 basis points during an Investment Grade Period, depending on the Partnership's credit rating then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from (i) 25 to 125 basis points during any period that is not an Investment Grade Period, depending on the leverage ratio then in effect and (ii) 12.5 to 100 basis points during an Investment Grade Period, depending on the Partnership's credit rating then in effect.

During any period that is not an Investment Grade Period, the revolving credit facility is guaranteed by Antero Midstream and its subsidiaries and is secured by mortgages on substantially all of Antero Midstream's and its subsidiaries' properties; provided that the liens securing the revolving credit facility shall be automatically released during an Investment Grade Period. The revolving credit facility contains restrictive covenants that may limit Antero Midstream's ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;

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

The revolving credit facility also requires Antero Midstream to maintain the following financial ratios:

- a consolidated interest coverage ratio, which is the ratio of Antero Midstream's consolidated EBITDA to its consolidated current interest charges of at least 2.5 to 1.0 at the end of each fiscal quarter; provided that during an Investment Grade Period, the Partnership will not to be subject to such ratio;
- a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 5.00 to 1.00 at the end of each fiscal quarter; provided that during an Investment Grade Period or at Antero Midstream's election (the "Financial Covenant Election"), the consolidated total leverage ratio shall be no more than 5.25 to 1.0; and
- after a Financial Covenant Election (and up to the commencement of an Investment Grade Period), a consolidated senior secured leverage ratio covenant rather than the consolidated total leverage ratio covenant, which is the ratio of consolidated senior secured debt to consolidated EBITDA, of not more than 3.75 to 1.0.

Antero Midstream was in compliance with the applicable covenants and ratios as of December 31, 2017 and December 31, 2018.

Antero Senior Notes. On November 5, 2013, Antero issued $1.0 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's other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's 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 may redeem all or part of the 2021 notes at any time at redemption prices ranging from 101.344% currently to 100.00% on or after November 1, 2019. If Antero undergoes a change of control, the holders of the 2021 notes will have the right to require Antero 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, Antero issued $600 million of 5.125% senior notes due December 1, 2022 (the "2022 notes") at par. On September 18, 2014, Antero 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's other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's 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 may redeem all or part of the 2022 notes at any time at redemption prices ranging from 102.563% currently to 100.00% on or after June 1, 2020. If Antero undergoes a change of control, the holders of the 2022 notes will have the right to require Antero 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, Antero 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's other outstanding senior notes. The 2023 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's 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 may redeem all or part of the 2023 notes at any time at redemption prices ranging from 104.219% to 100.00% on or after June 1, 2021. If Antero undergoes a change of control, the holders of the 2023 notes will have the right to require Antero 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, Antero 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's other outstanding senior notes. The 2025 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future

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restricted subsidiaries. Interest on the 2025 notes is payable on March 1 and September 1 of each year. Antero 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 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 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 undergoes a change of control, the holders of the 2025 notes will have the right to require Antero 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, 2017 and 2018.

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.

Antero Midstream Senior Notes. On September 13, 2016, Antero Midstream and its wholly-owned subsidiary, Antero Midstream Finance Corporation ("Midstream Finance Corp.") as co-issuers, issued $650 million in aggregate principal amount of 5.375% senior notes due September 15, 2024 (the "2024 Midstream notes") at par. The 2024 Midstream notes are unsecured and effectively subordinated to the Midstream Credit Facility to the extent of the value of the collateral securing the Midstream Credit Facility. The 2024 Midstream notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Midstream's wholly-owned subsidiaries, excluding Midstream Finance Corp., and certain of Antero Midstream's future restricted subsidiaries. Interest on the 2024 Midstream notes is payable on March 15 and September 15 of each year. Antero Midstream may redeem all or part of the 2024 Midstream notes at any time on or after September 15, 2019 at redemption prices ranging from 104.031% on or after September 15, 2019 to 100.00% on or after September 15, 2022. In addition, prior to September 15, 2019, Antero Midstream may redeem up to 35% of the aggregate principal amount of the 2024 Midstream notes with an amount of cash not greater than the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375% of the principal amount of the 2024 Midstream notes, plus accrued and unpaid interest. At any time prior to September 15, 2019, Antero Midstream may also redeem the 2024 Midstream notes, in whole or in part, at a price equal to 100% of the principal amount of the 2024 Midstream notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Midstream undergoes a change of control, the holders of the 2024 Midstream notes will have the right to require Antero Midstream to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2024 Midstream notes, plus accrued and unpaid interest.

Treasury Management Facility. Antero has a stand-alone revolving note with a lender which provides for up to $25 million of cash management obligations in order to facilitate Antero's 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, 2019. At December 31, 2017, there were no outstanding borrowings under this facility and $5.4 million at December 31, 2018 included in "Other current liabilities" on the Company's Consolidated Balance Sheet.

Contractual Obligations. A summary of our contractual obligations as of December 31, 2018 is provided in the table below. Contractual obligations listed exclude minimum fees that we will pay to Antero Midstream, our consolidated subsidiary, under

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gathering and compression, and water services agreements. Future capital contributions to unconsolidated affiliates are excluded from the table as neither the amounts nor the timing of the obligations can be determined in advance.

	Year Ended December 31,						
(in millions)	2019	2020	2021	2022	2023	Thereafter	Total
Credit Facility (1)	$ —	—	405	—	—	—	405
Treasury Management Facility (1)	5	—	—	—	—	—	5
Midstream Credit Facility (1)	—	—	—	990	—	—	990
Antero senior notes—principal (2)	—	—	1,000	1,100	750	600	3,450
Antero senior notes—interest (2)	182	182	155	129	51	60	759
Antero Midstream senior notes—principal (2)	—	—	—	—	—	650	650
Antero Midstream senior notes—interest (2)	35	35	35	35	35	35	210
Drilling rig and completion service commitments (3)	133	64	7	—	—	—	204
Firm transportation (4)	1,075	1,112	1,089	1,037	1,024	8,752	14,089
Processing, gathering, and compression services (5)	389	399	390	387	379	1,722	3,666
Office and equipment leases	15	13	11	9	7	49	104
Asset retirement obligations (6)	—	—	1	—	—	41	42
Total	$ 1,834	1,805	3,093	3,687	2,246	11,909	24,574

(1) Includes outstanding principal amounts at December 31, 2018. This table does not include future commitment fees, interest expense, or other fees on our Credit Facility or the Midstream 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 Antero's senior notes, unless such series of notes is refinanced. The maturity date of the Midstream Credit Facility is October 26, 2022

(2) Antero senior notes include the 5.375% notes due 2021, the 5.125% notes due 2022, the 5.625% notes due 2023, and the 5.00% notes due 2025. Antero Midstream senior notes include the 5.375% notes due 2024.

(3) Includes contracts for services provided by drilling rigs and completion fleets, which expire at various dates from February 2019 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.

(4) 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.

(5) Contractual commitments for processing, gathering, and compression services agreements represent minimum commitments under long-term agreements. This includes fees to be paid to the Joint Venture owned by Antero Midstream and MarkWest, as well as Antero Midstream's remaining commitments for the construction of its advanced wastewater treatment facility, which was placed in service in May 2018. 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 table does not include intracompany commitments.

(6) 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.

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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 measures 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. Also, 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, 2016, 2017, and 2018. 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 unproved properties for leases which have expired, or are expected to expire, was $163 million, $160 million, and $549 million for the years ended December 31, 2016, 2017, and 2018, 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.

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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 exceeded the estimated undiscounted future net cash flows (measured using futures prices), we would estimate the fair value of our proved properties and record an impairment charge for any excess of the carrying amount of the properties over the estimated fair value of the properties. We compared estimated undiscounted future net cash flows using futures pricing for our Utica and Marcellus Shale properties to the carrying values of those properties. Estimated undiscounted future net cash flows exceeded the carrying values at December 31, 2018, and thus, no further evaluation of our proved properties for impairment is required under GAAP. As a result, we have not recorded any impairment expenses associated with our proved properties during the years ended December 31, 2016, 2017 and 2018.

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 $0.55 per Mcf for gas and by approximately $5.00 per barrel for oil from future pricing levels at December 31, 2018, 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 significantly more than $0.55 per Mcf and $5.00 per barrel of oil from year-end 2018 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.

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, 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. 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 that expire at various dates from 2019 through 2038, 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, 2018, we have recognized a valuation allowance of $45 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.

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New Accounting Pronouncements

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases, which replaced most existing lease guidance in GAAP when it became effective on January 1, 2019. The standard requires lessees to record lease liabilities and right-of-use assets and we have elected to adopt ongoing effects of the new standard prospectively. The standard also provides for the election of practical expedients in applying and adopting the standard. Practical expedients adopted by the Company include, (i) not reassessing whether expired or existing contracts contain leases under the new definition of a lease and retaining lease classification for expired or existing leases, (ii) the use of hindsight in determining the lease term, the likelihood that a lessee purchase option will be exercised, and impairment assessment, (iii) carrying forward the existing accounting treatment for land easements, and (iv) combining lease and non-lease components by asset class.

Adoption of the standard will increase assets and liabilities on the Company's consolidated balance sheet as well as result in additional disclosures regarding lease expenses, assets, and liabilities. The Company will recognize right-of-use assets and lease liabilities related to certain contractual obligations for processing plants, drilling rigs, gas gathering lines, compressor stations, office space, and other office and field equipment. The Company estimates that adoption of the standard will result in the recognition of right-of-use assets and related liabilities of approximately $2.0 billion. The Company does not believe that adoption of the standard will impact its operational strategies, growth prospects, income or cash flows. The Company has updated internal controls impacted by the new standard and acquired software to collect and account for lease data under the standard.

Off-Balance Sheet Arrangements

As of December 31, 2018, we did not have any off balance sheet arrangements other than operating leases and contractual commitments for drilling rig and completion services, firm transportation, gas processing and fractionation, gathering, and compression services. 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, 2018, our commodity derivatives included fixed price swaps, basis differential swaps and collars at index-based pricing.

At December 31, 2018, we had in place natural gas swaps and collars covering portions of our projected production through 2023. Our commodity hedge position as of December 31, 2018 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 which settled during the year ended December 31, 2018, our revenues would have decreased by approximately $35 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, 2018.

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, 2018, the estimated fair value of our commodity derivative instruments was a net asset of $607 million, comprised of current assets and liabilities and noncurrent assets. At December 31, 2017, the estimated fair value of our commodity derivative instruments was a net asset of $1.3 billion, comprised of current and noncurrent assets and liabilities.

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

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from the following: commodity derivative contracts ($607 million at December 31, 2018) and the sale of our natural gas, NGLs and oil production ($440 million at December 31, 2018) 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 which 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 sixteen different counterparties, thirteen of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately $607 million at December 31, 2018 included the following derivative assets by bank counterparty: Morgan Stanley - $115 million; JP Morgan - $102 million; Scotiabank - $97 million; Citigroup - $91 million; Wells Fargo - $80 million; Canadian Imperial Bank of Commerce - $51 million; BNP Paribas - $24 million; Bank of Montreal - $14 million; Toronto Dominion - $8 million; PNC - $8 million; SunTrust - $7 million; Natixis - $7 million; and Capital One - $3 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, 2018 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, 2018, 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 our Credit Facility and the Midstream Credit Facility of our consolidated subsidiary, Antero Midstream. Each of these credit facilities has a floating interest rate. The average annual interest rate incurred on the Credit Facility and the Midstream Credit Facility during the year ended December 31, 2018 was approximately 3.69%. We estimate that a 1.0% increase in each of the applicable average interest rates for the year ended December 31, 2018 would have resulted in an estimated $12 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 report 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 Securities Exchange Act of 1934, as amended (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, 2018 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, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. In connection with the anticipated adoption of ASU No. 2016-02, Leases, we implemented additional controls and accounting processes related to the adoption of the lease standard. These changes have not materially affected the Company's 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.

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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, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018 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, 2018, as stated in their report which appears beginning on page F-2 in this report.

Item 9B. Other Information

Disclosure pursuant to Section 13(r) of the Securities Exchange Act of 1934

Pursuant to Section 13(r) of the Exchange Act, we may be required to disclose in our annual and quarterly reports to the SEC whether we or any of our “affiliates” knowingly engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by US economic sanctions. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Because the SEC defines the term “affiliate” broadly, it includes any entity under common “control” with us (and the term “control” is also construed broadly by the SEC).

The description of the activities below has been provided to us by Warburg Pincus LLC (“WP”), affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and are members of our board of directors, and (ii) beneficially own more than 10% of the outstanding common stock and are members of the board of directors of Endurance International Group Holdings, Inc. (together with its subsidiaries, “EIGI”). EIGI may therefore be deemed to be under common “control” with us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by EIGI. The disclosure does not relate to any activities conducted by us or by WP and does not involve our or WP’s management. Neither we nor WP has had any involvement in or control over the disclosed activities, and neither we nor WP has independently verified or participated in the preparation of the disclosure. Neither we nor WP is representing as to the accuracy or completeness of the disclosure nor do we or WP undertake any obligation to correct or update it.

We understand that EIGI intends to disclose the following in its next annual or quarterly SEC report:

On July 25, 2018, the Office of Foreign Assets Control ("OFAC") designated Electronics Katrangi Trading ("Katrangi") as a Specially Designated National ("SDN") pursuant to the Weapons of Mass Destruction Proliferators Sanctions Regulations, 31 C.F.R. Part 544. On July 30, 2018, during a regular compliance scan of EIGI's user base, EIGI identified the domain SGP-FRANCE.COM (the "Domain Name") which was listed as a website associated with Katrangi, on one of EIGI's platforms. The Domain Name was managed using one of EIGI's platforms by one of its reseller customers. Accordingly, there was no direct financial transaction between EIGI and the registered owner of the Domain Name and EIGI did not generate any revenue in connection with the Domain Name since Katrangi was added to the SDN list on July 25, 2018. Upon discovering the Domain Name on its platform, EIGI promptly suspended the Domain Name and removed it from its platform. EIGI reported the Domain Name to OFAC on August 7, 2018.

On November 6, 2018, EIGI terminated an end customer account (the "End Customer Account") that EIGI believed to be associated with Arian Bank, which was identified by OFAC as an SDN on November 5, 2018, pursuant to 31 C.F.R. Part 594. EIGI initially acquired the End Customer Account on January 23, 2014 as part of EIGI's acquisition of P.D.R Solutions FZC. EIGI reported the End Customer Account to OFAC as potentially the property of an SDN subject to blocking pursuant to Executive Order 13224. As of February 1, 2019, EIGI had not received any correspondence from OFAC regarding this matter.

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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 2019 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 13, 2019:

Name	Age	Title
Paul M. Rady	65	Chairman of the Board, Director and Chief Executive Officer
Glen C. Warren, Jr.	63	President, Director, Chief Financial Officer and Secretary
Michael N. Kennedy	44	Senior Vice President—Finance
Kevin J. Kilstrom	64	Senior Vice President—Production
Alvyn A. Schopp	60	Chief Administrative Officer, Regional Senior Vice President and Treasurer
Robert J. Clark	74	Director
Benjamin A. Hardesty	69	Director
Peter R. Kagan	50	Director
W. Howard Keenan, Jr.	68	Director
James R. Levy	42	Director
Joyce E. McConnell	64	Director
Paul J. Korus	62	Director

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

Paul M. Rady has served as Chief Executive Officer and Chairman of the Board of Directors since May 2004. Mr. Rady also served as Chief Executive Officer and Chairman of the Board of Directors of our predecessor company, Antero Resources Corporation, 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 the general partner of Antero Midstream since February 2014 as well as Chief Executive Officer and Chairman of the Board of Directors of the general partner of AMGP since April 2017. 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 President, Chief Financial Officer and Secretary and as a director since May 2004. Mr. Warren also served as President and Chief Financial Officer and as a director of our predecessor company, Antero Resources Corporation, 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 the general partner of Antero Midstream since February 2014 as well as President and Secretary and as a director of the Board of Directors of the general partner of AMGP since April 2017. 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.

Michael N. Kennedy has served as Senior Vice President of Finance of Antero and Chief Financial Officer of Antero Midstream since January 2016, prior to which he served as Vice President of Finance of Antero. beginning in August 2013. Mr. Kennedy has also served as AMGP's Chief Financial Officer and Senior Vice President of Finance since April 2017 and has served as Chief Financial Officer and Senior Vice President of Finance of the general partner of Antero Midstream since January 2016, prior to which he served as Vice President of Finance of the general partner of Antero Midstream beginning in February 2014. 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.

Kevin J. Kilstrom has served as Senior Vice President of Production since January 2016. He served as Vice President of Production from June 2007 to December 2015. Mr. Kilstrom has also served as Senior Vice President of Production of the general partner of Antero Midstream since January 2016, prior to which he served as Vice President of Production beginning in February 2014. Mr. Kilstrom has also served as Senior Vice President of Production of the general partner of AMGP since April 2017. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2006 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an Operations Manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University.

Alvyn A. Schopp has served as Regional Senior Vice President since January 2016 and as Chief Administrative Officer and Treasurer since October of 2013. He previously served as Regional Vice President beginning in October 2013 and as Vice President of Accounting and Administration and Treasurer beginning in January 2005. Mr. Schopp also served as Controller and Treasurer from 2003 to 2005. Mr. Schopp has served as Chief Administrative Officer, Senior Regional Vice President, and Treasurer of the general partner of Antero Midstream since January 2016, prior to which he served as Chief Administrative Officer, Regional Vice President and Treasurer of its general partner beginning in February 2014. Mr. Schopp has also served as Chief Administrative Officer, Senior Regional Vice President, and Treasurer of the general partner of AMGP since April 2017. 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, member of the Audit Committee and Chairman of the Compensation Committee since Antero's initial public offering in October 2013, and currently serves as a member of the Nominating & Governance Committee. Mr. Clark has been Chairman and Chief Executive Officer of 3 Bear Energy, LLC, a midstream energy company with operations in the Rocky Mountains, since its formation in March 2013. 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 Bradley University and serves on the board of trustees of Children's Hospital Colorado Foundation, 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 the board of directors of Antero.

Benjamin A. Hardesty has served as a director, Chairman of the nominating & governance committee and member of the compensation committee of Antero since Antero initial public offering in October 2013 and currently serves as a member of the 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 2011until its sale to B/E Aerospace in 2013. From l982 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.

Peter R. Kagan has served as a director of AMP GP since February 2014. Mr. Kagan also has served as a director of Antero since 2004 and as a director of AMGP GP since April 2017. Mr. Kagan has been with Warburg Pincus since 1997 where he leads the firm's investment activities in energy and natural resources. He is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. He is also a member of Warburg Pincus LLC's Executive Management Group. Mr. Kagan received a B.A. degree cum laude from Harvard College and J.D. and M.B.A. degrees with honors from the University of Chicago. Prior to joining Warburg Pincus, he worked in investment banking at Salomon Brothers in both New York and Hong Kong. Mr. Kagan currently also serves on the board of directors of Laredo Petroleum Holdings, Inc. as well as the boards of several private companies. In addition, he is a director of Street Squash and a trustee of Milton Academy.

Mr. Kagan 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. Kagan well-suited to serve as a member of our board of directors.

W. Howard Keenan, Jr. has served as a director of Antero since 2004. He has also served on the Board of Directors of the general partner of Antero Midstream since February 2014 and on the Board of Directors of the general partner of AMGP since 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: Ramaco Resources, 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.

James R. Levy has served as a director and member of our Compensation Committee since our initial public offering in October 2013. Mr. Levy is based in New York, joined Warburg Pincus in 2006 and is a member of the firm's Energy team. Prior to joining Warburg Pincus, Mr. Levy worked at Kohlberg & Company, a middle-market private equity investment firm, and Wasserstein Perella & Co. He is a Director of ATX Energy, Brigham Minerals, Brigham Resources, Chisholm Energy, Citizen Energy, Hawkwood Energy, Independence Resources Management, Laredo Petroleum, Ossidiana Energy and Terra Energy. Mr. Levy is a member of the Board of Directors of Prep for Prep and received his B.A. in history from Yale University.

Mr. Levy 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. Levy well suited to serve as a member of our board of directors.

Joyce E. McConnell has served as a director and member of the nominating & governance committee of Antero since February 2018. She has served as the Provost and Vice President for Academic Affairs at West Virginia University since 2014, where she is 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

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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.

Paul J. Korus has served as a director and member of the Audit Committee of Antero since December 2018. Mr. Korus has also served on the Board of Directors and Audit Committee of the general partner of Antero Midstream since January 2019. Mr. Korus was also appointed to the Board of Directors of SRC Energy Inc. in 2016, where he currently serves as Chairman of the Audit Committee and is a member of the Corporate Governance and Nominating Committee. 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 oversight of all financial areas including corporate planning, capital markets, accounting, tax, treasury, investor relations, internal audit and information technology. 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 is currently 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.

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 2019 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 2019 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 2019 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 2019 Annual Meeting of Stockholders.

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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 report beginning on page F 1.

(a)(3) Exhibits.

The exhibits marked with the asterisk symbol (*) are filed or furnished with this Annual Report on Form 10 K.

Exhibit Number	Description of Exhibit
2.1	Contribution, Conveyance and Assumption Agreement, dated as of September 17, 2015, by and among Antero Resources Corporation, Antero Midstream Partners LP and Antero Treatment LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 18, 2015).
2.2	Purchase and Sale Agreement, dated June 1, 2012, between Antero Resources Corporation and Vanguard Permian, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 5, 2012).
2.3	Purchase and Sale Agreement by and among Antero Resources Piceance LLC, Antero Resources Pipeline LLC and Ursa Resources Group II LLC, dated as of November 1, 2012 (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 6, 2012).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to 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 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 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 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 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 Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
4.5	Registration Rights Agreement 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 J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by

	reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
4.6	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 Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.7	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 Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.8	Form of 5.125% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.9	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 Antero Resource Corporation's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on November 26, 2014).

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4.10 Second Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of January 21, 2015, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.6 to Registration Statement Report on Form S-4 (Commission File No. 333-200605) filed on January 22, 2015).

4.11 Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).

4.12 Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of September 18, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2014).

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 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 Current Report on Form 8-K (Commission File No. 333-164876) filed on March 18, 2015).

4.15 Registration Rights Agreement related to the 5.625% Senior Notes due 2023, dated as of March 17, 2015, by and among Antero Resources Corporation, the subsidiary guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on March 18, 2015).

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 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 Current Report on Form 8-K (Commission File No. 333-164876) filed on December 29, 2016).

4.18 Registration Rights Agreement related to the 5.0% Senior Notes due 2025, dated as of December 21, 2016, by and among Antero Resources Corporation, the subsidiary guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on December 29, 2016).

4.19 Registration Rights Agreement, dated as of October 7, 2016, by and among Antero Resources Corporation and the Purchaser named therein (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016.

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 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 First Amended and Restated Gathering and Compression Agreement, dated as of February 13, 2018, by and between Antero Resources Corporation and Antero Midstream LLC (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 25, 2018).

10.4 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 Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 25, 2018).

10.5

	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).
10.6	Secondment Agreement, dated as of September 23, 2015, by and between Antero Midstream Partners LP, Antero Resources Midstream Management LLC, Antero Midstream LLC, Antero Water LLC, Antero Treatment LLC and Antero Resources Corporation (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2015).
10.7	Amended and Restated Services Agreement, dated as of September 23, 2015, by and among Antero Midstream Partners LP, Antero Resources Midstream Management LLC and Antero Resources Corporation (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2015).

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10.8	Services Agreement, dated as of May 9, 2017, by and among Antero Midstream GP LP, AMGP GP LLC, Antero IDR Holdings LLC and Antero Resources Corporation. (incorporated by reference to Exhibit 10.1 to Antero Midstream GP LP's Current Report on Form 8-K (Commission File No. 001-38075) filed on May 9, 2017).
10.9†*	Amended and Restated Water Services Agreement, dated as of February 12, 2019, by and between Antero Resources Corporation and Antero Water LLC.
10.10	Form of Amended and Restated Indemnification Agreement (incorporated by reference to Exhibit 10.1 to Amendment Current Report on Form 8-K (Commission File No. 001-36120) filed on April 17, 2018).
10.11	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 Current Report on Form 8-K (Commission File No. 333-164876) filed on October 11, 2013).
10.12	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).
10.13	Limited Liability Company Agreement of Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.14	Fifth Amended and Restated Credit Agreement, dated as of October 26, 2017, by and among Antero Resources Corporation, the lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on November 1, 2017).
10.15	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of December 21, 2018 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on December 28, 2018).
10.16	Credit Agreement, dated as of February 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
10.17	First Amendment to Credit Agreement, dated as of May 5, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
10.18	Second Amendment to Credit Agreement, dated as of July 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on July 31, 2014).
10.19	Third Amendment to Credit Agreement, dated as of October 16, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2014).
10.20	Fourth Amendment to Credit Agreement, dated as of November 10, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.6 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
10.21	Fifth Amendment to Credit Agreement, dated as of November 7, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.7 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
10.22	

	Sixth Amendment to Credit Agreement, dated as of February 17, 2015, by and among Antero Water LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on February 17, 2015).
10.23	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 Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 25, 2015).
10.24	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 Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 24, 2016).

10.25	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 10.2 to Current Report on Form 8-K (Commission File No. 001- 36120) filed on August 1, 2018).
10.26	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 Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).
10.27	Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Antero Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001- 36719) filed on November 12, 2014).
10.28	Form of Phantom Unit Grant Notice and Phantom Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to Antero Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001- 36719) filed on November 12, 2014).
10.29	Form of Restricted Unit Grant Notice and Restricted Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.5 to Antero Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001- 36719) filed on November 12, 2014).
10.30	Form of Bonus Unit Grant Notice and Bonus Unit Agreement (Form for Non-Employee Directors) under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.16 to Antero Midstream Partners' Annual Report on Form 10-K (Commission File No. 001- 36719) filed on February 24, 2016).
10.31	Common Stock Subscription Agreement, dated as of October 3, 2016, by and between Antero Resources Corporation and the Purchaser named on Schedule A thereto (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).
10.32	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 Current Report on Form 8-K (Commission File No. 001-36120) filed on October 10, 2018).
10.33	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 Current Report on Form 8-K (Commission File No. 001-36120) filed on October 10, 2018).
21.1*	Subsidiaries of Antero Resources Corporation.
23.1*	Consent of KPMG, LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
99.1*	Report of DeGolyer and MacNaughton, dated as of January 11, 2019, for proved reserves as of December 31, 2018.
99.2	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 Annual Report on Form 10-K (Commission File No. 001- 36120) filed on February 13, 2018).

99.3	Report of DeGolyer and MacNaughton, dated as of January 23, 2017, for proved reserves as of December 31, 2016 (incorporated by reference to Exhibit 99.1 to Annual Report on Form 10-K (Commission File No. 001- 36120) filed on February 28, 2017).
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2018, formatted in XBRL (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.

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.

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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 13, 2019

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 13, 2019
/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr.	President, Director, Chief Financial Officer and Secretary (principal financial officer)	February 13, 2019
/s/ K. PHIL YOO K. Phil Yoo	Vice President, Accounting and Chief Accounting Officer (principal accounting officer)	February 13, 2019
/s/ ROBERT J. CLARK Robert J. Clark	Director	February 13, 2019
/s/ BENJAMIN A. HARDESTY Benjamin A. Hardesty	Director	February 13, 2019
/s/ PETER R. KAGAN Peter R. Kagan	Director	February 13, 2019
/s/ W. HOWARD KEENAN, JR.	Director	February 13, 2019

W. Howard Keenan, Jr.

/s/ JAMES R. LEVY James R. Levy	Director	February 13, 2019
/s/ JOYCE E. MCCONNELL Joyce E. McConnell	Director	February 13, 2019
/s/ PAUL J. KORUS Paul J. Korus	Director	February 13, 2019

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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 its subsidiaries (the Company) as of December 31, 2017 and 2018, 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, 2018, 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, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018 based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting 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

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prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ KPMG LLP

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

Denver, Colorado
February 13, 2019

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ANTERO RESOURCES CORPORATION

Consolidated Balance Sheets

December 31, 2017 and 2018

(In thousands, except per share amounts)

	2017	2018
Assets		
Current assets:		
Cash and cash equivalents	$ 28,441	—
Accounts receivable, net of allowance for doubtful accounts of $1,320 and $-0- at December 31, 2017 and 2018, respectively	34,896	51,073
Accrued revenue	300,122	474,827
Derivative instruments	460,685	245,263
Other current assets	8,943	35,450
Total current assets	833,087	806,613
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	2,266,673	1,767,600
Proved properties	11,096,462	12,705,672
Water handling and treatment systems	946,670	1,013,818
Gathering systems and facilities	2,050,490	2,470,708
Other property and equipment	57,429	65,842
	16,417,724	18,023,640
Less accumulated depletion, depreciation, and amortization	(3,182,171)	(4,153,725)
Property and equipment, net	13,235,553	13,869,915
Derivative instruments	841,257	362,169
Investments in unconsolidated affiliates	303,302	433,642
Other assets	48,291	47,125
Total assets	$ 15,261,490	15,519,464
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 62,982	66,289
Accrued liabilities	443,225	465,070
Revenue distributions payable	209,617	310,827
Derivative instruments	28,476	532
Other current liabilities	17,796	10,822
Total current liabilities	762,096	853,540
Long-term liabilities:		
Long-term debt	4,800,090	5,461,688
Deferred income tax liability	779,645	650,788
Derivative instruments	207	—
Other liabilities	43,316	65,971
Total liabilities	6,385,354	7,031,987
Commitments and contingencies (Notes 13 and 14)		

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; 316,379 shares and 308,594 shares issued and outstanding at December 31, 2017 and 2018, respectively	3,164	3,086
Additional paid-in capital	6,570,952	6,485,174
Accumulated earnings	1,575,065	1,177,548
Total stockholders' equity	8,149,181	7,665,808
Noncontrolling interests in consolidated subsidiary	726,955	821,669
Total equity	8,876,136	8,487,477
Total liabilities and equity	$ 15,261,490	15,519,464

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income (Loss)

Years Ended December 31, 2016, 2017, and 2018

(In thousands, except per share amounts)

	2016	2017	2018
Revenue and other:			
Natural gas sales	$ 1,260,750	1,769,284	2,287,939
Natural gas liquids sales	432,992	870,441	1,177,777
Oil sales	61,319	108,195	187,178
Commodity derivative fair value gains (losses)	(514,181)	658,283	(87,594)
Gathering, compression, water handling and treatment	12,961	12,720	21,344
Marketing	393,049	258,045	458,901
Marketing derivative fair value gains (losses)	—	(21,394)	94,081
Gain on sale of assets	97,635	—	—
Total revenue and other	1,744,525	3,655,574	4,139,626
Operating expenses:			
Lease operating	50,090	89,057	136,153
Gathering, compression, processing, and transportation	882,838	1,095,639	1,339,358
Production and ad valorem taxes	66,588	94,521	126,474
Marketing	499,343	366,281	686,055
Exploration	6,862	8,538	4,958
Impairment of unproved properties	162,935	159,598	549,437
Impairment of gathering systems and facilities	—	23,431	9,658
Depletion, depreciation, and amortization	809,873	824,610	972,465
Accretion of asset retirement obligations	2,473	2,610	2,819
General and administrative (including equity-based compensation expense of $102,421, $103,445 and $70,414 in 2016, 2017 and 2018, respectively)	239,324	251,196	240,344
Total operating expenses	2,720,326	2,915,481	4,067,721
Operating income (loss)	(975,801)	740,093	71,905
Other income (expenses):			
Equity in earnings of unconsolidated affiliates	485	20,194	40,280
Interest	(253,552)	(268,701)	(286,743)
Loss on early extinguishment of debt	(16,956)	(1,500)	—
Total other expenses	(270,023)	(250,007)	(246,463)
Income (loss) before income taxes	(1,245,824)	490,086	(174,558)
Provision for income tax benefit	496,376	295,051	128,857
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(749,448)	785,137	(45,701)
Net income and comprehensive income attributable to noncontrolling interests	99,368	170,067	351,816
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (848,816)	615,070	(397,517)

Earnings (loss) per common share—basic	$ (2.88)	1.95	(1.26)
Earnings (loss) per common share—assuming dilution	$ (2.88)	1.94	(1.26)
Weighted average number of shares outstanding:			
Basic	294,945	315,426	316,036
Diluted	294,945	316,283	316,036

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Consolidated Statements of Equity

Years Ended December 31, 2016, 2017, and 2018

(In thousands)

	Common Stock Shares	Amount	Additional paid-in capital	Accumulated earnings	Noncontrolling interests	Total equity
Balances, December 31, 2015	277,036	$ 2,770	4,122,811	1,808,811	1,352,286	7,286,678
Issuance of common stock in public offering, net of underwriter discounts and offering costs	36,493	365	1,012,066	—	—	1,012,431
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,348	14	(21,274)	—	—	(21,260)
Issuance of common units by Antero Midstream Partners LP, net of underwriter discounts and offering costs	—	—	—	—	65,395	65,395
Issuance of common units by Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(15,190)	—	9,555	(5,635)
Sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation, net of	—	—	106,659	—	6,419	113,078

tax						
Equity-based compensation	—	—	94,409	—	8,012	102,421
Net income (loss) and comprehensive income (loss)	—	—	—	(848,816)	99,368	(749,448)
Distributions to noncontrolling interests	—	—	—	—	(75,082)	(75,082)
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)	—
	—	—	—	—	(152,352)	(152,352)

Distributions to noncontrolling interests						
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

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Consolidated Statements of Cash Flows

Years Ended December 31, 2016, 2017, and 2018

(In thousands)

	2016	2017	2018
Cash flows provided by (used in) operating activities:			
Net income (loss) including noncontrolling interests	$ (749,448)	785,137	(45,701)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion	812,346	827,220	975,284
Impairment of unproved properties	162,935	159,598	549,437
Impairment of gathering systems and facilities	—	23,431	9,658
Commodity derivative fair value (gains) losses	514,181	(658,283)	87,594
Gains on settled commodity derivatives	1,003,083	213,940	243,112
Premium paid on derivative contracts	—	—	(13,318)
Proceeds from derivative monetizations	—	749,906	370,365
Marketing derivative fair value (gains) losses	—	21,394	(94,081)
Gains on settled marketing derivatives	—	—	72,687
Deferred income tax benefit	(485,392)	(295,126)	(128,857)
Gain on sale of assets	(97,635)	—	—
Equity-based compensation expense	102,421	103,445	70,414
Loss on early extinguishment of debt	16,956	1,500	—
Equity in earnings of unconsolidated affiliates	(485)	(20,194)	(40,280)
Distributions of earnings from unconsolidated affiliates	7,702	20,195	46,415
Other	(12,488)	(1,907)	4,681
Changes in current assets and liabilities:			
Accounts receivable	39,857	(5,214)	(15,156)
Accrued revenue	(133,718)	(38,162)	(174,706)
Other current assets	1,774	(2,755)	(5,817)
Accounts payable	7,365	9,462	9,307
Accrued liabilities	18,853	64,862	63,562
Revenue distributions payable	34,040	45,628	101,210
Other current liabilities	(1,091)	2,214	(3,823)
Net cash provided by operating activities	1,241,256	2,006,291	2,081,987
Cash flows provided by (used in) investing activities:			
Additions to proved properties	(134,113)	(175,650)	—
Additions to unproved properties	(611,631)	(204,272)	(172,387)
Drilling and completion costs	(1,327,759)	(1,281,985)	(1,488,573)
Additions to water handling and treatment systems	(188,188)	(194,502)	(97,699)
Additions to gathering systems and facilities	(231,044)	(346,217)	(444,413)
Additions to other property and equipment	(2,694)	(14,127)	(7,514)
Investments in unconsolidated affiliates	(75,516)	(235,004)	(136,475)
Change in other assets	3,977	(12,029)	(3,663)
Proceeds from asset sales	171,830	2,156	—

Net cash used in investing activities	(2,395,138)	(2,461,630)	(2,350,724)
Cash flows provided by (used in) financing activities:			
Issuance of common stock	1,012,431	—	—
Issuance of common units by Antero Midstream Partners LP	65,395	248,956	—
Proceeds from sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation	178,000	311,100	—
Repurchases of common stock	—	—	(129,084)
Issuance of senior notes	1,250,000	—	—
Repayment of senior notes	(525,000)	—	—
Borrowings (repayments) on bank credit facilities, net	(677,000)	90,000	660,379
Make-whole premium on debt extinguished	(15,750)	—	—
Payments of deferred financing costs	(18,759)	(16,377)	(2,169)
Distributions to noncontrolling interests in consolidated subsidiary	(75,082)	(152,352)	(267,271)
Employee tax withholding for settlement of equity compensation awards	(26,895)	(24,174)	(17,020)
Other	(5,321)	(4,983)	(4,539)
Net cash provided by financing activities	1,162,019	452,170	240,296
Net increase (decrease) in cash and cash equivalents	8,137	(3,169)	(28,441)
Cash and cash equivalents, beginning of period	23,473	31,610	28,441
Cash and cash equivalents, end of period	$ 31,610	28,441	—
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 239,369	263,919	275,769
Decrease in accounts payable and accrued liabilities for additions to property and equipment	$ (152,093)	(547)	(47,717)

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements

Years Ended December 31, 2016, 2017, and 2018

(1) Organization

Antero Resources Corporation (individually referred to as “Antero” or the “Parent”) and its consolidated subsidiaries (collectively referred to as the “Company”) 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. Through its consolidated subsidiary, Antero Midstream Partners LP, a publicly-traded limited partnership (“Antero Midstream”), the Company has gathering and compression, as well as water handling and treatment, operations in the Appalachian Basin. 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, 2017 and 2018, and the results of its operations and its cash flows for the years ended December 31, 2016, 2017, and 2018. 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.

As of the date these financial statements were filed with the SEC, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified.

(b) Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Antero, 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.

For the years ended December 31, 2016, 2017 and 2018, we have determined that Antero Midstream is a VIE for which Antero is the primary beneficiary. Therefore, Antero Midstream’s accounts are consolidated in the Company’s consolidated financial statements. Antero is the primary beneficiary of Antero Midstream based on its power to direct the activities that most significantly impact Antero Midstream’s economic performance, and its obligation to absorb losses of, or right to receive benefits from, Antero Midstream that could be significant to Antero Midstream. In reaching the determination that Antero is the primary beneficiary of Antero Midstream, the Company considered the following:

.

Antero Midstream was formed to own, operate, and develop midstream energy assets to service Antero's production and completion activities under long-term service contracts.

- Antero owned 52.8% of the outstanding limited partner interests in Antero Midstream at December 31, 2018.
- Antero's officers and management group also act as management of Antero Midstream and AMGP under services and secondment agreements between the respective parties.
- Substantially all of Antero Midstream's revenues are derived from services provided to Antero.

All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements. Noncontrolling interest in the Company's consolidated financial statements represents the interests in Antero Midstream which are owned by the public and the incentive distribution rights in Antero Midstream. 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. 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.

The Company accounts for distributions received from equity method investees under the "nature of the distribution" approach. Under the nature of the distribution 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 which 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 which involve the use of significant estimates include derivative assets and liabilities, accrued revenue, deferred 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 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, 2018, the book overdraft included within accounts payable and revenue distributions payable was $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 and when 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 during the years ended December 31, 2016, 2017, and 2018. 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, drilling results, reservoir performance, commodity price outlooks,

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

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 unproved properties for leases which have expired, or are expected to expire, was $163 million, $160 million, and $549 million for the years ended December 31, 2016, 2017, and 2018, 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, anticipated capital expenditures, and a commensurate discount rate. Because estimated undiscounted future cash flows have exceeded the carrying value of the Company's proved properties at the end of each quarter, it has not been necessary for the Company to estimate the fair value of its properties under GAAP for successful efforts accounting. As a result, the Company has not recorded any impairment expenses associated with its proved properties during the years ended December 31, 2016, 2017 and 2018.

At December 31, 2018, the Company did not have capitalized costs related to exploratory wells in progress which 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 $700 million, $694 million, and $832 million for the years ended December 31, 2016, 2017, and 2018, 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 is 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 $101 million, $120 million, and $131 million for the years ended December 31, 2016, 2017, and 2018, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

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

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

There were no impairments for such assets during the year ended December 31, 2016. Impairment of gathering systems and facilities of $23 million and $10 million during the years ended December 31, 2017 and 2018, respectively, relates to gathering facilities no longer or not expected to be utilized.

(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 $9 million, $10 million, and $9 million for the years ended December 31, 2016, 2017, and 2018, respectively. A gain or loss is recognized upon the sale or disposal of other property and equipment.

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(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, 2018, the Company had $19 million of unamortized deferred financing costs included in other long term assets, and $35 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 $16 million, $13 million, and $13 million for the years ended December 31, 2016, 2017, and 2018, 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, as well as Antero Midstream's future closure and postclosure costs associated with the landfill, fresh water impoundments and waste water pits at its wastewater treatment facility. 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.

Antero Midstream is under no legal obligations, neither contractually nor under the doctrine of promissory estoppel, to restore or dismantle its gathering pipelines, compressor stations, water delivery pipelines and facilities and wastewater treatment facility upon abandonment. Antero Midstream's gathering pipelines, compressor stations, fresh water delivery pipelines and facilities and wastewater treatment facility have an indeterminate life, if properly maintained. Accordingly, Antero Midstream is not able to make a reasonable estimate of when future dismantlement and removal dates of its pipelines, compressor stations and facilities will occur.

(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, 2017 and 2018, 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.

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(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 month that the sale occurred. Variances between estimated sales and actual amounts received are recorded in the month payment is received and are not material. The Company recognizes natural gas revenues based on its entitlement share of natural gas that is produced based on its working interests in the properties. The Company records a revenue distribution payable to the extent it receives more than its proportionate share of production revenues. At December 31, 2017 and 2018, the Company had no production imbalance positions.

Under our natural gas sales contracts, we deliver natural gas to purchasers 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 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 further 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 the purchaser 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 the 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. The Company has 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.

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.

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(p) Gathering, compression, water handling and treatment revenue

Substantially all revenues from our gathering, compression, water handling and treatment operations are derived from intersegment transactions for services Antero Midstream provides to our exploration and production operations. The portion of such fees shown in our consolidated financial statements 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 or usage of Antero Midstream's gathering and compression systems. For gathering and compression revenue, Antero Midstream 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 in accordance with the gathering and compression agreement. For water handling and treatment revenue, Antero Midstream 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's 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 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, 2016, 2017, and 2018 are as follows:

	2016		2017		2018	
Company A	1	%	—	%	16	%
Company B	29		22		14	
Company C	13		15		7	
All others	57		63		63	
	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 sixteen different counterparties. The fair value of the Company's commodity derivative contracts of approximately $607 million (excluding short-term commodity derivatives related to our marketing activities) at December 31, 2018 includes the following values by bank counterparty: Morgan Stanley - $115 million; JP Morgan - $102 million; Scotiabank - $97 million; Citigroup - $91 million; Wells Fargo - $80 million; Canadian Imperial Bank of Commerce - $51 million; BNP Paribas - $24 million; Bank of Montreal - $14 million; Toronto Dominion - $8 million; PNC - $8 million; SunTrust - $7 million; Natixis - $7 million; and Capital One - $3 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, 2018 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 which 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) gathering and processing; (3) water handling and treatment; and (4) marketing and utilization of excess firm transportation capacity.

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 resell the Company's production to third parties located in foreign countries.

(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

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antidilutive. 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,		
	2016	2017	2018
Basic weighted average number of shares outstanding	294,945	315,426	316,036
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	294,945	316,283	316,036
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings per common share (1):			
Restricted stock units	6,740	1,521	2,844
Outstanding stock options	702	676	626
Performance stock units	659	1,054	1,705

(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 Standard

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases, which replaced most existing lease guidance in GAAP when it became effective on January 1, 2019. The standard requires lessees to record lease liabilities and right-of-use assets and we have elected to adopt the ongoing effects of the new standard prospectively. The standard also provides for the election of practical expedients in applying and adopting the standard. Practical expedients adopted by the Company include, (i) not reassessing whether expired or existing contracts contain leases under the new definition of a lease and retaining lease classification for expired or existing leases, (ii) the use of hindsight in determining the lease term, the likelihood that a lessee purchase option will be exercised, and impairment assessment, (iii) carrying forward the existing accounting treatment for land easements, and (iv) combining lease and non-lease components by asset class.

Adoption of the standard will increase assets and liabilities on the Company's consolidated balance sheet as well as result in additional disclosures regarding lease expenses, assets, and liabilities. The Company will recognize right-of-use assets and lease liabilities related to certain contractual obligations for office space, processing plants, drilling rigs, gas gathering lines, compressor stations, and other office and field equipment. The Company estimates that adoption of the standard will result in the recognition of right-of-use assets and related liabilities of approximately $2.0 billion. The Company does not believe that adoption of the standard will impact its operational strategies, growth prospects, income or cash flows. The Company has updated internal controls impacted by the new standard and acquired and implemented software to collect and account for lease data under the standard.

(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)Antero Midstream Partners LP

In 2014, the Company formed Antero Midstream to own, operate, and develop midstream energy assets that service Antero's 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 it provides services to Antero under long-term, fixed-fee contracts. AMGP indirectly owns the general partnership interest in Antero Midstream and directly owns capital interests in IDR LLC, which owns the incentive distribution rights in Antero Midstream. Antero Midstream is an unrestricted subsidiary as defined by Antero's senior secured revolving bank credit facility (the "Credit Facility"). As an unrestricted subsidiary, Antero Midstream and its subsidiaries are not guarantors of Antero's obligations, and Antero is not a guarantor of Antero Midstream's obligations (see Note 17).

On September 23, 2015, Antero contributed (i) all of the outstanding limited liability company interests of Antero Water LLC ("Antero Water") to Antero Midstream and (ii) all of the assets, contracts, rights, permits and properties owned or leased by Antero and used primarily in connection with the construction, ownership, operation, use or maintenance of Antero's advanced wastewater treatment facility under construction in Doddridge County, West Virginia, to Antero Treatment LLC ("Antero Treatment"), a subsidiary of Antero Midstream (collectively, (i) and (ii) are referred to herein as the "Contributed Assets"). In consideration for the Contributed Assets, Antero Midstream (i) paid to Antero a cash distribution equal to $552 million, less $171 million of assumed debt, (ii) issued to Antero 10,988,421 common units representing limited partner interests in Antero Midstream, (iii) distributed to Antero proceeds of approximately $241 million from a private placement of Antero Midstream common units, and (iv) has agreed to pay Antero (a) $125 million in cash if Antero Midstream delivers 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, 2018, Antero Midstream has delivered 128 million of the 176 million barrels and we expect to receive the entire amount of the contingent consideration for the 176 million barrels or more fresh water delivered during the period between January 1, 2017 and December 31, 2019, but Antero Midstream has delivered 71 million of the 219 million barrels and we do not expect Antero Midstream to deliver 219 million barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020.

Antero Midstream has an Equity Distribution Agreement (the "Distribution Agreement") pursuant to which Antero Midstream may sell, from time to time through brokers acting as its sales agents, common units representing limited partner interests having an aggregate offering price of up to $250 million. Sales of the common units are made by means of ordinary brokers' transactions on the New York Stock Exchange, at market prices, in block transactions, or as otherwise agreed to between Antero Midstream and the sales agents. Proceeds are used for general partnership purposes, which may include repayment of indebtedness and funding working capital or capital expenditures. Antero Midstream is under no obligation to offer and sell common units under the Distribution Agreement. During the year ended December 31, 2018, Antero Midstream did not sell any common units under the Distribution Agreement. During the year ended December 31, 2017, Antero Midstream issued and sold 777,262 common units under the Distribution Agreement, resulting in net proceeds of $26 million after deducting commissions and other offering costs. As of December 31, 2018, Antero Midstream had the capacity to issue additional common units under the Distribution Agreement up to an aggregate sales price of $157 million.

On February 6, 2017, Antero Midstream formed a joint venture (the "Joint Venture") to develop processing assets in Appalachia with MarkWest Energy Partners, L.P. ("MarkWest"), a wholly owned subsidiary of MPLX, L.P. (see Note 5). In conjunction with the formation of the Joint Venture, on February 10, 2017, Antero Midstream issued 6,900,000 common units, including common units issued pursuant to the underwriters' option to purchase additional common units, generating net proceeds of approximately $223 million. Antero Midstream used the net proceeds to fund the initial contribution to the Joint Venture, repay outstanding borrowings under its credit facility, and for general partnership purposes.

On March 30, 2016, Antero sold 8,000,000 of its Antero Midstream common units for $178 million. On September 11, 2017, Antero sold 10,000,000 of its Antero Midstream common units for $311 million. These sales of units are reflected in stockholders' equity as additional paid-in capital, net of taxes.

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Antero Midstream also owns a 15% equity interest in the gathering system of Stonewall Gas Gathering LLC ("Stonewall") which operates a 67-mile pipeline on which Antero is an anchor shipper.

Antero owned approximately 52.9% and 52.8% of the limited partner interests of Antero Midstream at December 31, 2017 and December 31, 2018, respectively.

(4)Revenue

(a) Disaggregation of Revenue

In the following table, revenue is disaggregated by type (in thousands). The table also identifies the reportable segment to which the disaggregated revenues relate. For more information on reportable segments, see Note 16—Segment Information.

	Year Ended December 31, 2016	2017	2018	Segment to which revenues relate
Revenues from contracts with customers:				
Natural gas sales	$ 1,260,750	1,769,284	2,287,939	Exploration and production
Natural gas liquids sales (ethane)	52,949	93,041	172,653	Exploration and production
Natural gas liquids sales (C3+ NGLs)	380,043	777,400	1,005,124	Exploration and production
Oil sales	61,319	108,195	187,178	Exploration and production
Gathering and compression	12,169	11,386	17,817	Gathering and processing
Water handling and treatment	792	1,334	3,527	Water handling and treatment
Marketing	393,049	258,045	458,901	Marketing
Total	2,161,071	3,018,685	4,133,139	
Income from derivatives and other sources	(416,546)	636,889	6,487	
Total revenue and other	$ 1,744,525	3,655,574	4,139,626	

(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, 2017 and 2018, our receivables from contracts with customers were $300 million and $475 million, respectively.

(5) Equity Method Investments

In 2016, Antero Midstream acquired a 15% equity interest in Stonewall Gas Gathering LLC ("Stonewall"), which operates a regional gathering pipeline on which Antero is an anchor shipper.

On February 6, 2017, Antero Midstream formed the Joint Venture to develop gas processing and fractionation assets in Appalachia with MarkWest, a wholly owned subsidiary of MPLX. Antero Midstream and MarkWest each own a 50% equity interest in the Joint Venture and MarkWest operates the Joint Venture assets, which consist of processing plants in West Virginia, and a one-third interest in a MarkWest fractionator in Ohio.

The Company's consolidated statements of operations and comprehensive income (loss) include Antero Midstream's proportionate share of the net income of equity method investees. When Antero Midstream records its proportionate share of net income, it increases equity income in the consolidated statements of operations and comprehensive income (loss) and the carrying

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value of that investment on the Company's consolidated balance sheet. When a distribution is received, it is recorded as a reduction to the carrying value of that investment on the consolidated balance sheet. The Company uses the equity method of accounting to account for its investments in Stonewall and the Joint Venture because Antero Midstream exercises significant influence, but not control, over the entities. The Company's judgment regarding the level of influence over its equity investments includes considering key factors such as Antero Midstream's ownership interest, representation on the board of directors, and participation in the policy-making decisions of Stonewall and the Joint Venture.

The following table is a reconciliation of investments in unconsolidated affiliates for the years ending December 31, 2017 and 2018 in thousands):

	Stonewall (2)	MarkWest Joint Venture	Total
Balance at December 31, 2016	$ 68,299	—	68,299
Investments (1)	—	235,004	235,004
Equity in net income of unconsolidated affiliates	10,304	9,890	20,194
Distributions from unconsolidated affiliates	(11,475)	(8,720)	(20,195)
Balance at December 31, 2017	67,128	236,174	303,302
Investments (1)	—	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

(1) Investments in the Joint Venture relate to capital contributions for construction of additional processing facilities.
(2) Distributions are net of operating and capital requirements retained by Stonewall.

(6) Accrued Liabilities

Accrued liabilities as of December 31, 2017 and 2018 consisted of the following items (in thousands):

	December 31, 2017	December 31, 2018
Capital expenditures	$ 155,300	113,237
Gathering, compression, processing, and transportation expenses	88,850	148,032
Marketing expenses	59,049	67,082
Interest expense	40,861	43,444
Other	99,165	93,275
	$ 443,225	465,070

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

(7) Long Term Debt

Long term debt was as follows at December 31, 2017 and 2018 (in thousands):

	December 31, 2017	December 31, 2018
Antero Resources:		
Credit Facility (a)	$ 185,000	405,000
5.375% senior notes due 2021 (b)	1,000,000	1,000,000
5.125% senior notes due 2022 (c)	1,100,000	1,100,000
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	1,520	1,241
Net unamortized debt issuance costs	(32,430)	(26,700)
Antero Midstream:		
Midstream Credit Facility (g)	555,000	990,000
5.375% senior notes due 2024 (h)	650,000	650,000
Net unamortized debt issuance costs	(9,000)	(7,853)
	$ 4,800,090	5,461,688

Antero Resources Corporation

(a) Senior Secured Revolving Credit Facility

Antero 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's assets and are subject to regular annual redeterminations. At December 31, 2018, the borrowing base under the Credit Facility was $4.5 billion and lender commitments were $2.5 billion. The next redetermination of the borrowing base is scheduled to occur in April 2019. 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, unless such series of notes is refinanced.

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 (i) a BBB- or better rating from Standard and Poor's and (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. 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's election at the time of borrowing, plus an applicable rate based on Antero's 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's election at the time of borrowing, plus an applicable rate based on Antero's credit rating which ranges from 12.5 basis points to 175 basis points. Antero was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2017 and 2018.

As of December 31, 2018, Antero 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. As of December 31, 2017, Antero had an outstanding balance under the Credit Facility of $185 million, with a weighted average interest rate of 2.96%, and outstanding letters of credit of $705 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's credit rating.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

(b) 5.375% Senior Notes Due 2021

On November 5, 2013, Antero 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's other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's 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 may redeem all or part of the 2021 notes at any time at redemption prices ranging from 101.344% currently to 100.00% on or after November 1, 2019. If Antero undergoes a change of control, the holders of the 2021 notes will have the right to require Antero 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 issued $600 million of 5.125% senior notes due December 1, 2022 (the "2022 notes") at par. On September 18, 2014, Antero 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's other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's 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 may redeem all or part of the 2022 notes at any time at redemption prices ranging from 102.563% currently to 100.00% on or after June 1, 2020. If Antero undergoes a change of control, the holders of the 2022 notes will have the right to require Antero 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 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's other outstanding senior notes. The 2023 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's 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 may redeem all or part of the 2023 notes at any time at redemption prices ranging from 104.219% to 100.00% on or after June 1, 2021. If Antero undergoes a change of control, the holders of the 2023 notes will have the right to require Antero 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 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's other outstanding senior notes. The 2025 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's 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 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 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 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 undergoes a change of control, the holders of the 2025 notes will have the right to require Antero 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 has a stand alone revolving note with a lender that is part of the Credit Facility lending consortium which provides for up to $25 million of cash management obligations in order to facilitate Antero's 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

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Years Ended December 31, 2016, 2017, and 2018

prime rate plus 1.0%. The note matures on June 1, 2019. At December 31, 2017, there were no outstanding borrowings under this facility and $5.4 million at December 31, 2018 included in "Other current liabilities" on the Company's Consolidated Balance Sheet.

Antero Midstream Partners LP

(g) Senior Secured Revolving Credit Facility – Antero Midstream

Antero Midstream has a senior secured revolving credit facility (the "Midstream Credit Facility") with a consortium of bank lenders. At December 31, 2018, lender commitments under the Midstream Credit Facility were $2.0 billion. The maturity date of the Midstream Credit Facility is October 26, 2022.

During any period that is not an Investment Grade Period (as such term is defined in the Midstream Credit Facility), the Midstream Credit Facility is ratably secured by mortgages on substantially all of the properties of Antero Midstream and guarantees from its restricted subsidiaries, as applicable. During an Investment Grade Period under the Midstream Credit Facility, the liens securing the Midstream Credit Facility are automatically released (subject to the provisions of the Midstream Credit Facility). The Midstream Credit Facility contains certain covenants, including restrictions on indebtedness and certain distributions to owners, and requirements with respect to leverage and interest coverage ratios. During any period that is not an Investment Grade Period under the Midstream Credit Facility, interest is payable at a variable rate based on LIBOR or the prime rate determined by Antero Midstream's election at the time of borrowing, plus an applicable rate based on Antero Midstream's borrowing base utilization which ranges from 25 basis points to 225 basis points. During an Investment Grade Period under the Midstream Credit Facility, interest is payable at a variable rate based on LIBOR or the prime rate determined by Antero Midstream's election at the time of borrowing, plus an applicable rate based on Antero Midstream's credit rating which ranges from 12.5 basis points to 200 basis points. Antero Midstream was in compliance with all of the financial covenants under the Midstream Credit Facility as of December 31, 2017 and 2018.

As of December 31, 2018, Antero Midstream had an outstanding balance under the Midstream Credit Facility of $990 million with a weighted average interest rate of 3.75%, and no letters of credit outstanding. As of December 31, 2017, Antero Midstream had an outstanding balance under the Midstream Credit Facility of $555 million with a weighted average interest rate of 2.81%. Commitment fees on the unused portion of the Midstream Credit Facility are due quarterly at rates ranging from (i) 0.25% to 0.375% of the unused portion (during an period that is not an Investment Grade Period) based on the leverage ratio and (ii) 0.175% to 0.375% of the unused portion (during an Investment Grade Period) based on Antero Midstream's credit rating.

(h)5.375% Senior Notes Due 2024 – Antero Midstream

On September 13, 2016, Antero Midstream and its wholly-owned subsidiary, Antero Midstream Finance Corporation ("Midstream Finance Corp.") as co-issuers, issued $650 million in aggregate principal amount of 5.375% senior notes due September 15, 2024 (the "2024 Midstream notes") at par. The 2024 Midstream notes are unsecured and effectively subordinated to the Midstream Credit Facility to the extent of the value of the collateral securing the Midstream Credit Facility. The 2024 Midstream notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Midstream's wholly-owned subsidiaries, excluding Midstream Finance Corp., and certain of Antero

Midstream's future restricted subsidiaries. Interest on the 2024 Midstream notes is payable on March 15 and September 15 of each year. Antero Midstream may redeem all or part of the 2024 Midstream notes at any time on or after September 15, 2019 at redemption prices ranging from 104.031% on or after September 15, 2019 to 100.00% on or after September 15, 2022. In addition, prior to September 15, 2019, Antero Midstream may redeem up to 35% of the aggregate principal amount of the 2024 Midstream notes with an amount of cash not greater than the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375% of the principal amount of the 2024 Midstream notes, plus accrued and unpaid interest. At any time prior to September 15, 2019, Antero Midstream may also redeem the 2024 Midstream notes, in whole or in part, at a price equal to 100% of the principal amount of the 2024 Midstream notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Midstream undergoes a change of control, the holders of the 2024 Midstream notes will have the right to require Antero Midstream to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2024 Midstream notes, plus accrued and unpaid interest.

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Years Ended December 31, 2016, 2017, and 2018

(8) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2017 and 2018 (in thousands):

	2017	2018
Asset retirement obligations—beginning of year	$ 32,736	34,610
Obligations settled	(22)	—
Obligations incurred	4,044	9,981
Revisions to prior estimates	(4,758)	11,569
Accretion expense	2,610	2,819
Asset retirement obligations—end of year	$ 34,610	58,979

Revisions to prior estimates in 2018 are primarily due to an increase in estimated abandonment costs for vertical wells. Revisions to prior estimates in 2017 are primarily due to an increase in the estimated economic lives of our wells as a result of increases in commodity prices in 2017 and improved well performance. Asset retirement obligations are included in other liabilities on the Company's consolidated balance sheets.

(9) Equity Based Compensation

Antero 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's Board of Directors. A total of 8,351,638 shares were available for future grant under the Plan as of December 31, 2018.

Antero Midstream's general partner is authorized to grant up to 10,000,000 common units representing limited partner interests in Antero Midstream under the Antero Midstream Partners LP Long-Term Incentive Plan (the "Midstream Plan") to non-employee directors of its general partner and certain officers, employees, and consultants of Antero Midstream and its affiliates (which include Antero). A total of 7,932,261 common units were available for future grant under the Midstream Plan as of December 31, 2018.

The Company's equity based compensation expense, by type of award, was as follows for the years ended December 31, 2016, 2017, and 2018 (in thousands):

	Year Ended December 31,		
	2016	2017	2018

Restricted stock unit awards	$ 73,081	70,866	41,505
Stock options	2,578	2,375	1,799
Performance share unit awards	8,685	10,797	9,659
Antero Midstream phantom unit awards	16,095	17,461	15,351
Equity awards issued to directors	1,982	1,946	2,100
Total expense	$ 102,421	103,445	70,414

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 the Company's common stock on the date of the grant.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

A summary of restricted stock unit award activity for the year ended December 31, 2018 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2017	3,424,084	$ 28.51	$ 65,058
Granted	687,626	$ 20.69	
Vested	(1,933,130)	$ 29.90	
Forfeited	(466,095)	$ 25.65	
Total awarded and unvested—December 31, 2018	1,712,485	$ 24.57	$ 16,080

Intrinsic values are based on the closing price of the Company's stock on the referenced dates. As of December 31, 2018, there was $27 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 2.3 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 the Company's common stock on the dates of grant.

A summary of stock option activity for the year ended December 31, 2018 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2017	660,512	$ 50.48	7.06	$ —
Granted	—	$ —		
Exercised	—	$ —		
Forfeited	(80,895)	$ 50.00		
Expired	—	$ —		
Outstanding at December 31, 2018	579,617	$ 50.55	5.81	$ —
Vested or expected to vest as of December 31, 2018	579,617	$ 50.55	5.81	$ —
Exercisable at December 31, 2018	462,217	$ 50.69	5.69	$ —

Intrinsic values are based on the exercise price of the options and the closing price of the Company's 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 the Company's 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.

No stock options were granted during the years ended December 31, 2016, 2017 and 2018.

As of December 31, 2018, there was $0.5 million of unamortized equity based compensation expense related to unvested stock options. That expense is expected to be recognized over a weighted average period of approximately 0.3 years.

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

Performance Share Unit Awards

Performance Share Unit Awards Based on Price Targets

In 2016, the Company granted performance share unit awards ("PSUs") to certain of its executive officers that are based on price targets. The vesting of these PSUs is conditioned on the closing price of the Company's 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.

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 the Company's common stock relative to the TSR of a peer group of companies over a three-year performance period. The number of common shares 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.

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 common stock reaching a target price per share equal to 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 the Company's 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.

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.

Summary Information for Performance Share Unit Awards

A summary of PSU activity for the year ended December 31, 2018 is as follows:

	Number of units	Weighted average grant date fair value
Total awarded and unvested—December 31, 2017	1,283,843	$ 28.29
Granted	756,466	$ 23.61
Vested	(41,666)	$ 27.38
Forfeited	(231,344)	$ 27.89
Total awarded and unvested—December 31, 2018	1,767,299	$ 26.36

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 the Company's common stock on the date of the grant, assuming the achievement of the performance condition.

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The following table presents information regarding the weighted average fair values for market-based PSUs granted during the years ended December 31, 2017 and 2018, and the assumptions used to determine the fair values:

	Year Ended December 31, 2017	2018
Dividend yield	— %	— %
Volatility	42 %	41 %
Risk-free interest rate	1.40 %	2.49 %
Weighted average fair value of awards granted	$ 26.21	$ 24.85

As of December 31, 2018, there was $20 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 1.9 years.

Antero Midstream Partners Phantom Unit Awards

Phantom units granted by Antero Midstream vest subject to the satisfaction of service requirements, upon the completion of which common units in Antero Midstream are delivered to the holder of the phantom units. Phantom units also contain distribution equivalent rights which entitle the holder of vested common units to receive a “catch up” payment equal to common unit distributions paid by Antero Midstream during the vesting period of the phantom unit award. These phantom units are treated, for accounting purposes, as if Antero Midstream distributed the units to Antero. Antero recognizes compensation expense as the units are granted to its employees, and a portion of the expense is allocated to Antero Midstream. Expense related to each phantom 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 Midstream’s common units on the date of grant.

A summary of phantom unit awards activity for the year ended December 31, 2018 is as follows:

	Number of units	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2017	1,042,963	$ 28.69	$ 30,288

Granted	260,847	$ 25.84		
Vested	(577,566)	$ 28.63		
Forfeited	(143,244)	$ 28.08		
Total awarded and unvested—December 31, 2018	583,000	$ 27.63	$	12,470

Intrinsic values are based on the closing price of Antero Midstream's common units on the referenced dates. As of December 31, 2018, there was $12 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 2.5 years.

(10) Financial Instruments

The carrying values of accounts receivable and accounts payable at December 31, 2017 and 2018 approximated market values because of their short term nature. The carrying values of the amounts outstanding under the Credit Facility and Midstream Credit Facility at December 31, 2017 and 2018 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 the Antero's senior notes was approximately $3.5 billion and $3.3 billion at December 31, 2017 and 2018. Based on Level 2 market data inputs, the fair value of Antero Midstream's senior notes was approximately $670 million at December 31, 2017 and $608 million at December 31, 2018.

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

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

(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, 2016, 2017, and 2018. 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 has 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, 2018, the Company's fixed price natural gas positions from January 1, 2019 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):

	Natural gas MMbtu/day	Weighted average index

		price
Three months ending March 31, 2019:		
NYMEX ($/MMBtu)	2,330,000	$ 3.62
Three months ending June 30, 2019:		
NYMEX ($/MMBtu)	755,000	$ 3.26
Three months ending September 30, 2019:		
NYMEX ($/MMBtu)	755,000	$ 3.32
Three months ending December 31, 2019:		
NYMEX ($/MMBtu)	755,000	$ 3.45
Year ending December 31, 2020:		
NYMEX ($/MMBtu)	1,417,500	$ 3.00
Year ending December 31, 2021:		
NYMEX ($/MMBtu)	710,000	$ 3.00
Year ending December 31, 2022:		
NYMEX ($/MMBtu)	850,000	$ 3.00
Year ending December 31, 2023:		
NYMEX ($/MMBtu)	90,000	$ 2.91

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Notes to Consolidated Financial Statements (Continued)

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As of December 31, 2018, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of Chicago City Gate to the NYMEX Henry Hub natural gas price, totaled 225,000 MMbtu/day for January 2019 with pricing differentials ranging from $0.215 to $0.40.

As of December 31, 2018, the Company's fixed price natural gas collar positions from April 1, 2019 through December 31, 2019 were as follows (abbreviations in the table refer to the index to which the collar position is tied, as follows: NYMEX=Henry Hub.

	Natural gas	Weighted average index price	
	MMbtu/day	Ceiling price	Floor price
Three months ending June 30, 2019:			
NYMEX ($/MMBtu)	1,575,000	$ 3.30	$ 2.50
Three months ending September 30, 2019:			
NYMEX ($/MMBtu)	1,575,000	$ 3.30	$ 2.50
Three months ending December 31, 2019:			
NYMEX ($/MMBtu)	1,575,000	$ 3.52	$ 2.50

An initial premium of $13 million was paid at the inception of natural gas collar contracts with one counterparty, and is recorded as a derivative asset measured at fair value.

(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. As a result of severe cold weather in the local area in January resulting in wide basis premiums at the index for these contracts, the Company realized a cash gain on these contracts of $73 million during the year ended December 31, 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 loss in the fourth quarter of 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.

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

(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, 2017 and 2018. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	December 31, 2017 Balance sheet location	Fair value (In thousands)	December 31, 2018 Balance sheet location	Fair value (In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity derivatives - current	Derivative instruments	$ 460,685	Derivative instruments	$ 245,263
Commodity derivatives - noncurrent	Derivative instruments	841,257	Derivative instruments	362,169
Total asset derivatives		1,301,942		607,432
Liability derivatives not designated as hedges for accounting purposes:				
Marketing derivatives - current	Derivative instruments	21,394	Derivative instruments	—
Commodity derivatives - current	Derivative instruments	7,082	Derivative instruments	532
Commodity derivatives - noncurrent	Derivative instruments	207	Derivative instruments	—
Total liability derivatives		28,683		532
Net derivatives		$ 1,273,259		$ 606,900

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, 2017			December 31, 2018		
	Gross amounts on balance sheet	Gross amounts offset on	Net amounts	Gross amounts on balance	Gross amounts offset on	Net amounts of assets

		balance sheet	of assets (liabilities) on balance sheet	sheet	balance sheet	(liabilities) on balance sheet
Commodity derivative assets	$ 1,367,554	(65,612)	1,301,942	$ 658,830	(51,398)	607,432
Commodity derivative liabilities	$ (72,901)	65,612	(7,289)	$ (51,930)	51,398	(532)
Marketing derivative assets	$ 311,083	(311,083)	—	$ —	—	—
Marketing derivative liabilities	$ (332,477)	311,083	(21,394)	$ —	—	—

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, 2016, 2017, and 2018 (in thousands):

	Statement of operations location	Year ended December 31, 2016	2017	2018
Commodity derivative fair value gains (losses)	Revenue	$ (514,181)	658,283	(87,594)
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 year ended December 31, 2017 and 2018. 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.

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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) Income Taxes

For the years ended December 31, 2016, 2017, and 2018, income tax expense (benefit) consisted of the following (in thousands):

	Year ended December 31,		
	2016	2017	2018
Current income tax expense (benefit)	$ (10,984)	75	—
Deferred income tax benefit	(485,392)	(295,126)	(128,857)
Total income tax benefit	$ (496,376)	(295,051)	(128,857)

Income tax expense (benefit) differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 35% for the years ended December 31, 2016 and 2017, and 21% for the year ended December 31, 2018, to income or loss before taxes as a result of the following (in thousands):

	Year ended December 31,		
	2016	2017	2018
Federal income tax expense (benefit)	$ (436,038)	171,530	(36,657)
State income tax expense (benefit), net of federal benefit	(20,364)	10,779	(12,627)
Change in Federal tax rate, net of state benefit (1)	—	(427,962)	—
Change in State tax rate, net of federal effect	—	—	(40,415)
Nondeductible equity-based compensation	3,691	12,098	6,079
Noncontrolling interest in Antero Midstream	(34,780)	(59,523)	(73,881)
Change in valuation allowance	(10,852)	(2,073)	28,116
Other	1,967	100	528
Total income tax benefit	$ (496,376)	(295,051)	(128,857)

(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%.

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Years Ended December 31, 2016, 2017, and 2018

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, 2017 and 2018 is as follows (in thousands):

	2017	2018
Deferred tax assets:		
Net operating loss carryforwards	$ 727,522	734,255
Equity-based compensation	12,062	10,633
Investment in Antero Midstream	38,613	—
Other	11,236	15,726
Total deferred tax assets	789,433	760,614
Valuation allowance	(17,361)	(45,477)
Net deferred tax assets	772,072	715,137
Deferred tax liabilities:		
Unrealized gains on derivative instruments	442,855	271,747
Oil and gas properties	1,058,543	1,055,850
Investment in Antero Midstream	—	11,258
Other	50,319	27,070
Total deferred tax liabilities	1,551,717	1,365,925
Net deferred tax liabilities	$ (779,645)	(650,788)

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 $17 million and $45 million at December 31, 2017 and 2018, respectively related to state net operating loss ("NOL") carryforwards. The increase in the valuation allowance from $17 million at December 31, 2017 to $45 million at December 31, 2018, is due to an additional allowance provided for Colorado NOLs because of a change in Colorado apportionment regulations. 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. In 2016, the Company reversed unrecognized benefits recorded in prior years due to the expiration of the applicable statutes of limitations. The removal of the unrecognized benefits did not impact the Company's 2016 effective tax rate. The Company will continue to monitor potential uncertain tax positions, but does not anticipate any changes within the next year. The Company had an $11 million unrecognized tax benefit at the beginning of the year ended

December 31, 2016, which was reduced in the year ended December 31, 2016, and has no other balances through December 31, 2018.

As of December 31, 2018, the Company has U.S. federal and state NOL carryforwards of $3.0 billion and $2.3 billion, respectively, which expire at various dates from 2019 to 2038.

Tax years 2015 through 2018 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 2014 through 2018.

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(13) 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, 2018 (in millions).

(in millions)	Firm transportation (a)	Processing, gathering and compression (b)	Drilling rigs and completion services (c)	Office and equipment (d)	Total
2019	$ 1,075	389	133	15	1,612
2020	1,112	399	64	13	1,588
2021	1,089	390	7	11	1,497
2022	1,037	387	—	9	1,433
2023	1,024	379	—	7	1,410
Thereafter	8,752	1,722	—	49	10,523
Total	$ 14,089	3,666	204	104	18,063

(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 agreements for certain of its production that will allow it to realize the value of its NGLs. The minimum payment obligations under the agreements are presented in the table. Certain of these obligations are accounted for as operating leases.

The Company has various gathering and compression service agreements with third parties that provide for payments based on volumes gathered or compressed. The minimum payment obligations under these agreements are presented in the table.

The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest. The values in the table also include minimum processing fees to be paid to the Joint Venture owned by Antero Midstream and MarkWest.

The table does not include intracompany commitments. Future capital contributions to unconsolidated affiliates are excluded from the table as neither the amounts nor the timing of the obligations can be determined in advance.

(c) Drilling Rigs and Completion Services Commitments

The Company has obligations under agreements with service providers to procure drilling rigs and completion services. 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. Certain of these obligations are accounted for as operating leases.

(d) Office and Equipment Leases

The Company leases various office space and equipment under capital and operating lease arrangements. Rental expense under operating leases was $9 million, $7 million, and $9 million for the years ended December 31, 2016, 2017, and 2018, respectively.

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(14) Contingencies

SJGC

The Company is the plaintiff in two lawsuits against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively, "SJGC") pending in United States District Court in Colorado. In March 2015, the Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC had short paid, and continued to short pay, the Company in connection with two nearly identical long term gas contracts. Under those contracts, SJGC are long term purchasers of 80,000 MMBtu/day of the Company's natural gas production. Deliveries under the contracts began in October 2011 and the term of the contracts continues through October 2019. The price for gas was based on specified indices in the contracts. Beginning in October 2014, SJGC began short paying the Company based on price indices unilaterally selected by SJGC and not the applicable index specified in the contracts. SJGC claimed that the index price specified in the contracts, and the index at which SJGC paid for deliveries from 2011 through September 2014, was no longer appropriate under the contracts because a market disruption event (as defined by the contract) had occurred and, as a result, a new index price was required to be determined by the parties. The Company rejected SJGC's contention that a market disruption event occurred. SJGC's actions constituted a breach of the contracts by failing to pay the Company based on the express price terms of the contracts and paying the Company based on unilaterally selected price indices in violation of the contracts' remedial provisions. On May 8, 2017, a jury in the United States District Court in Colorado returned a unanimous verdict finding in favor of Antero's positions in the lawsuit against SJGC. On July 21, 2017, final judgment on the jury's unanimous verdict was entered by the court. On August 18, 2017, SJGC filed post-judgment motions with the court. On March 23, 2018, the court denied SJGC's post-judgment motions. On April 20, 2018, SJGC appealed the final judgment to the United States Court of Appeals for the Tenth Circuit and the appeal remains pending.

Subsequent to the entry of judgment, SJGC has continued to short pay the Company on the basis of unilaterally selected price indices and not the index specified in the contract. Accordingly, on December 21, 2017, Antero filed suit against SJGC to recover for its damages since March of 2017. The second lawsuit remains pending.

Through December 31, 2018, the Company estimates that it is owed approximately $86 million (gross damages, including interest) more than SJGC has paid using the indices unilaterally selected by them. Substantially all of this amount has not been accrued in the Company's financial statements. The Company will vigorously seek recovery from SJGC of all underpayments and damages, including interest, based on the contracted price.

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 point in Braxton, 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 for the alleged failure to deliver "TCO pool" gas under the Contracts. WGL has appealed this

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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 Colorado Court of Appeals did not address the issue of whether WGL's claims were independently barred by the prior arbitration's findings.

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 gas began in April 2017 and continued each month through December 2017 in varying quantities. In defense of its conduct, WGL has 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 has failed to receive the quantity of gas required under the Contracts, the Company has resold the quantities not taken and invoiced WGL for cover damages pursuant to the terms of the Contracts. WGL has refused to pay for the invoiced cover damages as required by the Contracts and has also short paid the Company for, among other things, certain amounts of gas received by WGL. Through December 31, 2018, these damages amounted to approximately $109 million (gross damages, including interest). This amount has not been accrued in the Company's financial statements. The Company is currently pursuing its cover damages in a lawsuit filed in Colorado district court on October 24, 2017. The Company will continue to vigorously seek recovery of its cover damages and other unpaid amounts, including interest, as part of its claims against WGL. WGL's claims have been consolidated with Antero's claims in the same district court and trial is scheduled to begin on June 10, 2019. WGL has quantified its damages claim for the alleged failure to deliver TCO Pool gas and is seeking approximately $40 million from Antero.

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 delivery point in Braxton, West Virginia 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.

(15) Related Parties

Certain of the Company's shareholders, including members of its executive management group, own a significant interest in the Company and, either through their representatives or directly, serve as members of the Board of Directors of Antero and the Boards of Directors of the general partners of Antero Midstream and AMGP. These same groups or individuals own limited partner interests in Antero Midstream and common shares and other interests in AMGP, which indirectly owns the incentive distribution rights in Antero Midstream. Antero's executive management group also manages the operations and business affairs of Antero Midstream and AMGP.

Antero Midstream's operations comprise substantially all of the operations of our gathering and processing segment and our water handling and treatment segment. Substantially all of the revenues for those segments in the years ended December 31, 2016, 2017, and 2018 were derived from transactions with Antero. See Note 16 for the operating results of the Company's reportable segments.

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(16) Segment Information

See Note 2(t) for a description of the Company's determination of its reportable segments. Revenues from gathering and processing and water handling and treatment operations are primarily derived from intersegment transactions for services provided to the Company's exploration and production operations. 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 of each segment. General and administrative expenses are allocated to the gathering and processing and water handling and treatment segments 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 are transacted at prices which approximate market. Accounting policies for each segment as 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, 2016, 2017, and 2018 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2016:						
Sales and revenues:						
Third-party	$ 1,334,656	16,028	792	393,049	—	1,744,525
Intersegment	18,324	291,916	281,475	—	(591,715)	—
Total	$ 1,352,980	307,944	282,267	393,049	(591,715)	1,744,525
Operating expenses:						
Lease operating	$ 50,651	—	136,386	—	(136,947)	50,090
Gathering, compression, processing, and transportation	1,146,221	28,098	—	—	(291,481)	882,838
Depletion, depreciation, and	709,127	70,847	29,899	—	—	809,873

amortization						
General and administrative	186,672	39,832	14,331	—	(1,511)	239,324
Other	241,755	(809)	14,401	499,343	(16,489)	738,201
Total	2,334,426	137,968	195,017	499,343	(446,428)	2,720,326
Operating income (loss)	$ (981,446)	169,976	87,250	(106,294)	(145,287)	(975,801)
Equity in earnings of unconsolidated affiliates	$ —	485	—	—	—	485
Segment assets	$ 12,512,973	1,750,354	615,687	37,890	(661,354)	14,255,550
Capital expenditures for segment assets	$ 2,220,688	231,044	188,188	—	(144,491)	2,495,429

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	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2017:						
Sales and revenues:						
Third-party	$ 3,406,203	11,386	1,334	236,651	—	3,655,574
Intersegment	17,358	385,080	374,697	—	(777,135)	—
Total	$ 3,423,561	396,466	376,031	236,651	(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
Depletion, depreciation, and amortization	704,152	87,268	33,190	—	—	824,610
General and administrative	195,153	40,337	18,475	—	(2,769)	251,196
Other	261,578	23,535	17,061	366,281	(13,476)	654,979
Total	2,695,770	190,287	258,428	366,281	(595,285)	2,915,481
Operating income (loss)	$ 727,791	206,179	117,603	(129,630)	(181,850)	740,093
Equity in earnings of unconsolidated affiliates	$ —	20,194	—	—	—	20,194
Segment assets	$ 13,074,027	2,253,163	804,296	36,701	(906,697)	15,261,490
Capital expenditures for segment assets	$ 1,859,481	346,217	194,502	—	(183,447)	2,216,753

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2018:						
Sales and revenues:						
Third-party	$ 3,565,300	17,817	3,527	552,982	—	4,139,626
Intersegment	(87,472)	503,332	503,846	—	(919,706)	—
Total	$ 3,477,828	521,149	507,373	552,982	(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	48,998	552	—	(503,090)	1,339,358
Impairment of unproved properties	549,437	—	—	—	—	549,437
Impairment of gathering systems and facilities	—	9,658	—	—	—	9,658
Depletion, depreciation, and amortization	841,645	84,057	46,763	—	—	972,465
General and administrative	181,305	46,609	15,020	—	(2,590)	240,344
Other	129,947	258	(88,973)	686,055	93,019	820,306
Total	3,637,466	189,580	236,066	686,055	(681,446)	4,067,721
Operating income (loss)	$ (159,638)	331,569	271,307	(133,073)	(238,260)	71,905
Equity in earnings of unconsolidated affiliates	$ —	40,280	—	—	—	40,280
Segment assets	$ 12,986,945	2,465,858	1,077,004	34,499	(1,044,842)	15,519,464
Capital expenditures for segment assets	$ 1,923,488	444,413	97,699	—	(255,014)	2,210,586

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(17) Condensed Consolidating Financial Information

Each of Antero's wholly-owned subsidiaries has fully and unconditionally guaranteed Antero's senior notes. Antero Midstream and its subsidiaries have been designated as unrestricted subsidiaries under the Credit Facility and the indentures governing Antero's senior notes, and do not guarantee any of Antero's obligations (see Note 7). 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 which is not Antero or a restricted subsidiary of Antero, such subsidiary guarantor will be released from its obligations under its subsidiary guarantee if the sale or other disposition does not violate the covenants set forth in the indentures governing the notes.

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

The following Condensed Consolidating Balance Sheets at December 31, 2017 and 2018, 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, 2016, 2017, and 2018, present financial information for Antero 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. Antero's wholly-owned subsidiaries are not restricted from making distributions to the Parent.

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Condensed Consolidating Balance Sheet

December 31, 2017

(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 20,078	—	8,363	—	28,441
Accounts receivable, net	33,726	—	1,170	—	34,896
Intercompany receivables	6,459	—	110,182	(116,641)	—
Accrued revenue	300,122	—	—	—	300,122
Derivative instruments	460,685	—	—	—	460,685
Other current assets	8,273	—	670	—	8,943
Total current assets	829,343	—	120,385	(116,641)	833,087
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,266,673	—	—	—	2,266,673
Proved properties	11,460,615	—	—	(364,153)	11,096,462
Water handling and treatment systems	—	—	942,361	4,309	946,670
Gathering systems and facilities	17,929	—	2,032,561	—	2,050,490
Other property and equipment	57,429	—	—	—	57,429
	13,802,646	—	2,974,922	(359,844)	16,417,724
Less accumulated depletion, depreciation, and amortization	(2,812,851)	—	(369,320)	—	(3,182,171)
Property and equipment, net	10,989,795	—	2,605,602	(359,844)	13,235,553
Derivative instruments	841,257	—	—	—	841,257
Investment in Antero Midstream	(573,926)	—	—	573,926	—
Contingent acquisition consideration	208,014	—	—	(208,014)	—
Investments in unconsolidated affiliates	—	—	303,302	—	303,302
Other assets	35,371	—	12,920	—	48,291
Total assets	$ 12,329,854	—	3,042,209	(110,573)	15,261,490

Liabilities and Equity
Current liabilities:

Accounts payable	$ 54,340	—	8,642	—	62,982
Intercompany payable	110,182	—	6,459	(116,641)	—
Accrued liabilities	338,819	—	106,006	(1,600)	443,225
Revenue distributions payable	209,617	—	—	—	209,617
Derivative instruments	28,476	—	—	—	28,476
Other current liabilities	17,587	—	209	—	17,796
Total current liabilities	759,021	—	121,316	(118,241)	762,096
Long-term liabilities:					
Long-term debt	3,604,090	—	1,196,000	—	4,800,090
Deferred income tax liability	779,645	—	—	—	779,645
Contingent acquisition consideration	—	—	208,014	(208,014)	—
Derivative instruments	207	—	—	—	207
Other liabilities	42,906	—	410	—	43,316
Total liabilities	5,185,869	—	1,525,740	(326,255)	6,385,354
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,516,469	(1,516,469)	—
Common stock	3,164	—	—	—	3,164
Additional paid-in capital	5,565,756	—	—	1,005,196	6,570,952
Accumulated earnings	1,575,065	—	—	—	1,575,065
Total stockholders' equity	7,143,985	—	1,516,469	(511,273)	8,149,181
Noncontrolling interests in consolidated subsidiary	—	—	—	726,955	726,955
Total equity	7,143,985	—	1,516,469	215,682	8,876,136
Total liabilities and equity	$ 12,329,854	—	3,042,209	(110,573)	15,261,490

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

Condensed Consolidating Balance Sheet

December 31, 2018

(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	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:					
Natural 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	(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
Other current liabilities	4,621	—	2,052	4,149	10,822
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)	—
Other liabilities	57,890	—	8,081	—	65,971
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

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

Condensed Consolidating Statement of Operations and Comprehensive Income

Year Ended December 31, 2016

(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 1,260,750	—	—	—	1,260,750
Natural gas liquids sales	432,992	—	—	—	432,992
Oil sales	61,319	—	—	—	61,319
Gathering, compression, water handling and treatment	—	—	586,352	(573,391)	12,961
Marketing	393,049	—	—	—	393,049
Commodity derivative fair value losses	(514,181)	—	—	—	(514,181)
Gain on sale of assets	93,776	—	3,859	—	97,635
Other income	18,324	—	—	(18,324)	—
Total revenue and other	1,746,029	—	590,211	(591,715)	1,744,525
Operating expenses:					
Lease operating	50,651	—	136,387	(136,948)	50,090
Gathering, compression, processing, and transportation	1,146,221	—	28,097	(291,480)	882,838
Production and ad valorem taxes	69,485	—	(2,897)	—	66,588
Marketing	499,343	—	—	—	499,343
Exploration	6,862	—	—	—	6,862
Impairment of unproved properties	162,935	—	—	—	162,935
Depletion, depreciation, and amortization	710,012	—	99,861	—	809,873
Accretion of asset retirement obligations	2,473	—	—	—	2,473
General and administrative	186,672	—	54,163	(1,511)	239,324
Change in fair value of contingent acquisition consideration	—	—	16,489	(16,489)	—
Total operating expenses	2,834,654	—	332,100	(446,428)	2,720,326
Operating income (loss)	(1,088,625)	—	258,111	(145,287)	(975,801)
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	485	—	485
Interest	(232,455)	—	(21,893)	796	(253,552)

Loss on early extinguishment of debt	(16,956)	—	—	—	(16,956)
Equity in earnings (loss) of Antero Midstream	(7,156)	—	—	7,156	—
Total other expenses	(256,567)	—	(21,408)	7,952	(270,023)
Income (loss) before income taxes	(1,345,192)	—	236,703	(137,335)	(1,245,824)
Provision for income tax benefit	496,376	—	—	—	496,376
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(848,816)	—	236,703	(137,335)	(749,448)
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	99,368	99,368
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (848,816)	—	236,703	(236,703)	(848,816)

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)

Year Ended December 31, 2017

(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	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

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)

Year Ended December 31, 2018

(In thousands)

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries (Antero Midstream)	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 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 unproved properties	549,437	—	—	—	549,437
Impairment of gathering systems and facilities	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
Change in fair value 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):					
	—	—	40,280	—	40,280

Equity in earnings of unconsolidated affiliates					
Interest	(224,977)	—	(61,906)	140	(286,743)
Equity in earnings (loss) of Antero Midstream	(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)

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2016

(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	$ (848,816)	—	236,703	(137,335)	(749,448)
Adjustment to reconcile net income (loss) to net cash provided by operating activities:					
Depletion, depreciation, amortization, and accretion	712,485	—	99,861	—	812,346
Change in fair value of contingent acquisition consideration	(16,489)	—	16,489	—	—
Impairment of unproved properties	162,935	—	—	—	162,935
Commodity derivative fair value losses	514,181	—	—	—	514,181
Gains on settled commodity derivatives	1,003,083	—	—	—	1,003,083
Deferred income tax benefit	(485,392)	—	—	—	(485,392)
Gain on sale of assets	(93,776)	—	(3,859)	—	(97,635)
Equity-based compensation expense	76,372	—	26,049	—	102,421
Loss on early extinguishment of debt	16,956	—	—	—	16,956
Equity in earnings of Antero Midstream	7,156	—	—	(7,156)	—
Equity in earnings of unconsolidated affiliates	—	—	(485)	—	(485)
Distributions of earnings from unconsolidated affiliates	—	—	7,702	—	7,702
Other	(14,302)	—	1,814	—	(12,488)
Distributions from subsidiaries	107,364	—	—	(107,364)	—
Changes in current assets and liabilities	(36,519)	—	(5,667)	9,266	(32,920)
Net cash provided by operating activities	1,105,238	—	378,607	(242,589)	1,241,256
Cash flows provided by (used in) investing activities:					

Additions to proved properties	(134,113)	—	—	—	(134,113)
Additions to unproved properties	(611,631)	—	—	—	(611,631)
Drilling and completion costs	(1,462,984)	—	—	135,225	(1,327,759)
Additions to water handling and treatment systems	32	—	(188,220)	—	(188,188)
Additions to gathering systems and facilities	(2,944)	—	(228,100)	—	(231,044)
Additions to other property and equipment	(2,694)	—	—	—	(2,694)
Investments in unconsolidated affiliates	—	—	(75,516)	—	(75,516)
Change in other assets	304	—	3,673	—	3,977
Proceeds from asset sales	161,830	—	10,000	—	171,830
Net cash used in investing activities	(2,052,200)	—	(478,163)	135,225	(2,395,138)
Cash flows provided by (used in) financing activities:					
Issuance of common stock	1,012,431	—	—	—	1,012,431
Issuance of common units by Antero Midstream	—	—	65,395	—	65,395
Sale of common units in Antero Midstream by Antero Resources Corporation	178,000	—	—	—	178,000
Issuance of senior notes	600,000	—	650,000	—	1,250,000
Repayment of senior notes	(525,000)	—	—	—	(525,000)
Repayments on bank credit facility, net	(267,000)	—	(410,000)	—	(677,000)
Make-whole premium on debt extinguished	(15,750)	—	—	—	(15,750)
Payments of deferred financing costs	(8,324)	—	(10,435)	—	(18,759)
Distributions	—	—	(182,446)	107,364	(75,082)
Employee tax withholding for settlement of equity compensation awards	(21,260)	—	(5,635)	—	(26,895)
Other	(5,157)	—	(164)	—	(5,321)
Net cash provided by financing activities	947,940	—	106,715	107,364	1,162,019
Net increase in cash and cash equivalents	978	—	7,159	—	8,137
Cash and cash equivalents, beginning of period	16,590	—	6,883	—	23,473
Cash and cash equivalents, end of period	$ 17,568	—	14,042	—	31,610

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

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 unproved properties	159,598	—	—	—	159,598
Impairment of gathering systems and facilities	—	—	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)
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)	—
	87,466	—	(18,160)	6,729	76,035

Changes in current assets and liabilities					
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

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

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
Change in fair value of contingent acquisition consideration	93,019	—	(93,019)	—	—
Impairment of unproved properties	549,437	—	—	—	549,437
Impairment of gathering systems and facilities	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 of Antero Midstream	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:					
Issuance of common units by Antero Midstream	—	—	—	—	—
Repurchases of common stock	(129,084)	—	—	—	(129,084)
Borrowings 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	$ —	—	—	—	—

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

(18) Quarterly Financial Information (Unaudited)

The Company's quarterly consolidated financial information for the years ended December 31, 2017 and 2018 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, 2017:				
Total operating revenues	$ 1,195,579	790,389	647,880	1,021,726
Total operating expenses	694,236	666,646	719,932	834,667
Operating income (loss)	501,343	123,743	(72,052)	187,059
Net income (loss) and comprehensive income (loss) including noncontrolling interest	305,558	39,965	(90,000)	529,614
Net income attributable to noncontrolling interest	37,162	45,097	45,063	42,745
Net income (loss) attributable to Antero Resources Corporation	268,396	(5,132)	(135,063)	486,869
Earnings (loss) per common share—basic	$ 0.85	(0.02)	(0.43)	1.54
Earnings (loss) per common share—assuming dilution	$ 0.85	(0.02)	(0.43)	1.54

	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	$ 0.05	(0.43)	(0.49)	(0.39)

Earnings (loss) per common share—diluted	$ 0.05	(0.43)	(0.49)	(0.39)

(19) 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)	2017	2018
Proved properties	$ 11,096,462	12,705,672
Unproved properties	2,266,673	1,767,600
	13,363,135	14,473,272
Accumulated depletion and depreciation	(2,783,832)	(3,615,680)
Net capitalized costs	$ 10,579,303	10,857,592

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

(b) Costs Incurred in Certain Oil and Gas Activities

	Year ended December 31,		
(In thousands)	2016	2017	2018
Acquisition costs:			
Proved property	$ 134,113	175,650	—
Unproved property	611,631	204,272	172,387
Development costs	1,000,903	897,287	1,164,800
Exploration costs	326,856	384,698	323,773
Total costs incurred	$ 2,073,503	1,661,907	1,660,960

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

	Year ended December 31,		
(In thousands)	2016	2017	2018
Revenues	$ 1,755,061	2,747,920	3,652,894
Operating expenses:			
Production expenses	999,516	1,279,217	1,601,985
Exploration expenses	6,862	8,538	4,958
Depletion and depreciation	700,274	694,332	832,326
Impairment of unproved properties	162,935	159,598	549,437
Results of operations before income tax (expense) benefit	(114,526)	606,235	664,188
Income tax (expense) benefit	43,334	(228,096)	(156,350)
Results of operations	$ (71,192)	378,139	507,838

(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, 2016, 2017, and 2018 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

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

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, 2015	9,533	587	26	13,215
Revisions	(2,069)	275	3	(404)
Extensions, discoveries and other additions	1,990	99	9	2,637
Production	(505)	(27)	(2)	(676)
Purchases of reserves	475	23	2	624
Sales of reserves in place	(10)	—	—	(10)
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

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2016	4,426	401	13	6,914
December 31, 2017	5,587	467	16	8,488
December 31, 2018	6,669	600	20	10,389
Proved undeveloped reserves:				
December 31, 2016	4,988	556	25	8,472
December 31, 2017	5,511	522	22	8,773
December 31, 2018	4,756	452	26	7,622

Significant items included in the categories of proved developed and undeveloped reserve changes for the years 2016, 2017, and 2018 in the above table include the following:

2016 Changes in Reserves

- Extensions, discoveries and other additions of 2,637 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales, which was aided in 2016 by longer laterals than in previous years and the utilization of advanced completion techniques.
- Purchases of 624 Bcfe relate to the acquisition of developed and undeveloped leasehold acreage in both the Marcellus and Utica Shales.
- Net downward revisions of 404 Bcfe include:
- Upward revisions of 1,359 Bcfe are due to an increase in our actual and assumed future ethane recovery rate based on existing sales contracts for ethane.
- Upward performance revisions of 762 Bcfe primarily relate to improved well performance.

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Years Ended December 31, 2016, 2017, and 2018

- Downward revisions of 2,478 Bcfe were due to the impact of the SEC 5-year development rule. Due to the SEC 5-year development rule, these primarily dry gas reserves were displaced by our updated development plan targeting more liquids-rich areas in our portfolio which have better economic returns.
- Downward revisions of 47 Bcfe were due to the decreases in prices for natural gas, NGLs, and oil.
- A downward revision of 10 Bcfe was related to our sale of producing and non-producing leasehold in Pennsylvania.
- We produced 676 Bcfe during the year ended December 31, 2016.

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 5-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 5-year development plan, and downward revisions of 2,280 Bcfe for locations that were not developed within 5 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 5-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 5-year development plan, and downward revisions of 2,464 Bcfe for locations that were not developed within 5 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.

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2016, 2017, and 2018

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 net operating loss 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)	2016	2017	2018
Future cash inflows	$ 36,800	55,824	64,199
Future production costs	(21,275)	(26,375)	(30,007)
Future development costs	(3,902)	(3,312)	(3,453)
Future net cash flows before income tax	11,623	26,137	30,739
Future income tax expense	(1,042)	(4,104)	(5,505)
Future net cash flows	10,581	22,033	25,234
10% annual discount for estimated timing of cash flows	(7,294)	(13,406)	(14,756)
Standardized measure of discounted future net cash flows	$ 3,287	8,627	10,478

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

December 31, 2016	$ 2.39
December 31, 2017	$ 3.23
December 31, 2018	$ 3.56

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

	Year ended December 31,		
(in millions)	2016	2017	2018
Sales of oil and gas, net of productions costs	$ (756)	(1,469)	(2,051)
Net changes in prices and production costs	(1,540)	3,918	707
Development costs incurred during the period	733	627	755

Net changes in future development costs	212	229	37
Extensions, discoveries and other additions	673	1,448	1,925
Acquisitions	66	258	—
Divestitures	(7)	—	—
Revisions of previous quantity estimates	461	734	(53)
Accretion of discount	363	368	1,018
Net change in income taxes	12	(1,159)	(563)
Other changes	(163)	386	76
Net increase	54	5,340	1,851
Beginning of year	3,233	3,287	8,627
End of year	$ 3,287	8,627	10,478