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

FORM 10-K

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

For the fiscal year ended December 31, 2019

or

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

Commission File No. 001-36120

ANTERO RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

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

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

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

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

Securities Registered Pursuant to Section 12(g) of the Act: **None.**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b 2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☒ No

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 28, 2019, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $1.5 billion based on the $5.53 per share closing price of Antero Resources Corporation's common stock as reported on that day on the New York Stock Exchange

The registrant had 286,677,115 shares of common stock outstanding as of February 7, 2020.

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

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

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

- uncertainty regarding our future operating results; and
- our other plans, objectives, expectations and intentions contained in this Annual Report on Form 10-K.

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

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

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

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

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

GLOSSARY OF COMMONLY USED TERMS

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

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

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

"Bbl/d." Bbl per day.

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

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

"*Btu*." British thermal unit.

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

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

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

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

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

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

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

"EPA." United States Environmental Protection Agency.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"MMcfe/d." MMcfe per day.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PART I

Items 1 and 2. Business and Properties

Our Company and Organizational Structure

Antero Resources Corporation (individually referred to as "Antero") and its consolidated subsidiaries (collectively referred to as "Antero Resources," the "Company," "we," "us" or "our") are engaged in the exploration, development, and acquisition of natural gas, NGLs, and oil properties in the Appalachian Basin in West Virginia and Ohio. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs, and oil from unconventional formations. As of December 31, 2019, we held approximately 541,000 net acres of oil and gas properties located in the Appalachian Basin in West Virginia and Ohio. Our corporate headquarters are in Denver, Colorado.

Ownership in Antero Midstream

In 2014, we formed Antero Midstream Partners LP ("Antero Midstream Partners") to own, operate, and develop midstream energy assets that service our production. Antero Midstream Partners' assets consist of gathering systems and compression facilities, water handling and treatment facilities, and interests in processing and fractionation plants, through which it provides services to us under long-term, fixed-fee contracts.

On March 12, 2019, pursuant to the Simplification Agreement, dated as of October 9, 2018, by and among Antero Midstream GP LP ("AMGP"), Antero Midstream Partners and certain of their affiliates (the "Simplification Agreement") (i) AMGP was converted from a limited partnership to a corporation under the laws of the State of Delaware and changed its name to Antero Midstream Corporation (together with its consolidated subsidiaries, as appropriate, "Antero Midstream"), and (ii) an indirect, wholly owned subsidiary of Antero Midstream was merged with and into Antero Midstream Partners, with Antero Midstream Partners surviving the merger as an indirect, wholly owned subsidiary of Antero Midstream (together, along with the other transactions contemplated by the Simplification Agreement, the "Transactions"). In connection with the Transactions, we received $297 million in cash and 158.4 million shares of Antero Midstream's common stock, par value $0.01 per share, in exchange for our 98,870,335 common units representing limited partner interests in Antero Midstream Partners owned immediately prior to the Transactions.

Prior to the Transactions, our ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and we consolidated Antero Midstream Partners' financial position and results of operations into our consolidated financial statements. The Transactions resulted in us owning approximately 31% of Antero Midstream's common stock. As a result, we no longer hold a controlling interest in Antero Midstream Partners and now have an interest in Antero Midstream that provides significant influence, but not control, over Antero Midstream. Thus, effective March 13, 2019, we no longer consolidate Antero Midstream Partners in our consolidated financial statements and account for our interest in Antero Midstream using the equity method of accounting. Because Antero Midstream Partners does not meet the requirements of a discontinued operation, Antero Midstream Partners' results of operations continue to be included in our consolidated statement of operations and comprehensive income (loss) through March 12, 2019. Please see Note 3 to the consolidated financial statements for more information on the Transactions.

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

General

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

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

(1) Estimated proved reserve volumes and values were calculated assuming partial ethane recovery, with rejection of the remaining ethane, and using the unweighted twelve-month average of the first-day-of-the-month prices for the period ended December 31, 2019, which were $2.41 per MMBtu for natural gas based on a $2.63 per MMBtu NYMEX reference price, $10.59 per Bbl for ethane, $29.47 per Bbl for C3+ NGLs and $45.75 per Bbl for oil for the Appalachian Basin based on a $55.65 per Bbl WTI reference price.

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

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

(4) Gross potential drilling locations are comprised of 328 locations classified as proved undeveloped, 1,958 locations classified as probable and 99 locations classified as possible. See "Item 1A. Risk Factors" for risks and uncertainties related to developing our potential well locations contained in our proved, probable, and possible reserve categories.

Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to profitably grow our reserves and production, primarily on our existing multi-year project inventory.

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. We have 2,385 potential horizontal well locations on our existing leasehold acreage within our proved, probable, and possible reserve categories.

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

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

2019 and Recent Developments and Highlights

Reserves, Production, and Financial Results

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

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

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

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

2019 Capital Spending and 2020 Capital Budget

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

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

Hedge Position

At December 31, 2019, we had fixed price swap contracts in place for January 1, 2020 through December31, 2023 for 1.7 Tcf of our projected natural gas production at a weighted average index price of $2.84 per MMBtu. These hedging contracts include contracts for the year ending December 31, 2020 of 815 Bcf of natural gas at a weighted average price of $2.87 per MMBtu. We also have fixed price swaps for NGLs and Oil for approximately 15 MMBbls for the year ending December 31, 2020 at weighted average index prices of $0.50 to $0.81 per gallon and $55.63 per Bbl, respectively. Additionally, we have basis swaps in place for January 1, 2020 through December 31, 2024 for 95 Bcf of our projected natural gas production with pricing differentials ranging from $0.35 to $0.53 per MMBtu. See Note 11 to the consolidated financial statements for more information on our current hedge position.

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

Credit Facility

At December 31, 2019, the borrowing base under our senior secured revolving credit facility (the "Credit Facility") was $4.5 billion and lender commitments were $2.64 billion. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the earliest stated redemption date of any series of Antero's senior notes then outstanding. The borrowing base under the Credit Facility is redetermined annually and is based on the estimated future cash flows from our proved oil and gas reserves and our commodity derivative positions. The next redetermination is scheduled to occur in April 2020. At

December 31, 2019, we had $552 million of borrowings, with a weighted average interest rate of 3.28%, and $623 million of letters of credit outstanding under the revolving credit facility. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Senior Secured Revolving Credit Facility" for a description of the Credit Facility.

Debt Repurchase Program

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

Share Repurchase Program

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

Our Properties and Operations

Estimated Proved Reserves

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

Reserves Presentation

The following table summarizes our estimated proved reserves, related Standardized measure, and PV-10 at December31, 2017, 2018 and 2019. The decrease in pre-tax estimated proved reserves PV-10 value as compared to 2018, was due primarily to lower SEC pricing and the deconsolidation of Antero Midstream Partners from Antero Resources' financial statements. The deconsolidation resulted in Antero Resources recording the full fees paid to Antero Midstream Partners for services rendered and no longer recording the capital expenditures associated with Antero Midstream Partners. Prior to deconsolidation, Antero Resources' consolidated reserves included the elimination of full fees paid by Antero Resources to Antero Midstream Partners and the inclusion of the operating costs and capital associated with Antero Midstream Partners.

Our estimated proved reserves are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent engineers, DeGolyer and MacNaughton ("D&M"). We refer to D&M as our independent engineers. A copy of the summary report of D&M with respect to our reserves at December 31, 2019 is filed as Exhibit 99.1 to this Annual Report on Form 10-K. Within D&M, the technical person primarily responsible for reviewing our reserves estimates was Gregory K. Graves, P.E. Mr. Graves is a Registered Professional Engineer in the State of Texas (License No. 70734), is a member of both the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers, and has in excess of 34 years of experience in oil and gas reservoir studies and reserves evaluations. Mr. Graves graduated from the University of Texas at Austin in 1984 with a Bachelor of Science degree in Petroleum Engineering. Reserves at December 31, 2017, 2018 and 2019 were prepared assuming partial ethane recovery, and rejection of the remaining ethane. When ethane is rejected at the processing plant, it is left in the gas stream and sold with the methane gas.

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

(1) PV-10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. PV-10 is a non-GAAP financial measure. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the Standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the Standardized measure is dependent on the unique tax situation of each company, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the Standardized measure and the PV-10 amount is the discounted amount of estimated future income taxes. Future income taxes are not basin specific and therefore the Standardized measure is only at a company level. See Note 21 to the consolidated financial statements for more information about the calculation of Standardized measure.

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

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

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

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

(3) 12 month average prices used at December 31, 2019 were $2.41 per MMBtu for natural gas, $10.59 per Bbl for ethane, $29.47 per Bbl for C3+ NGLs, and $45.75 per Bbl for oil for the Appalachian Basin based on a $55.65 WTI reference price.

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

Changes in Proved Reserves During 2019

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

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

Extensions, discoveries, and other additions of 3,705 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales. Included in the extensions are 1,202 Bcfe of volumes associated with a third party acreage trade. Upward revisions of 63 Bcfe related to well performance. Net downward revisions of 1,705 Bcfe related to optimization of our five-year development plan. This figure includes upward revisions of 595 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2018 to proved undeveloped at December 31, 2019 due to their addition to our five-year development plan, and downward revisions of 2,300 Bcfe for locations that were not developed within five years of initial booking as proved reserves. Downward revisions of 157 Bcfe were due to decreases in prices for natural gas, NGLs, and oil. Downward revisions of 164 Bcfe were due to an increase in fee structure resulting from the deconsolidation of Antero Midstream Partners. Deconsolidation of Antero Midstream Partners resulted in Antero Resources recording the full fees paid to Antero Midstream Partners for services rendered and no longer including future capital expenditures associated with Antero Midstream Partners' assets in future development costs. Prior to deconsolidation, Antero Resources' consolidated reserves included the elimination of full fees paid by Antero Resources to Antero Midstream Partners and the inclusion of the operating costs and capital incurred by Antero Midstream Partners. Upward revisions of 315 Bcfe were due to an increase in our assumed future ethane recovery. Our estimated proved reserves as of December 31, 2019 totaled approximately 18,893 Bcfe, an increase of 5% from the prior year.

Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated proved undeveloped reserves during 2019 (in Bcfe):

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

Extensions, discoveries, and other additions during 2019 of 3,433 Bcfe of proved undeveloped reserves resulted from delineation and developmental drilling in the Marcellus and Utica Shales. Included in the extensions are 1,173 Bcfe of volumes associated with a third party acreage trade. Upward revisions of 141 Bcfe related to well performance. Net downward revisions of 1,705 Bcfe related to optimization of our five-year development plan. This figure includes upward revisions of 595 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2018 to proved undeveloped at December 31, 2019 due to their addition to our five-year development plan, and downward revisions of 2,300 Bcfe for locations that were not developed within five years of initial booking as proved reserves. Downward revisions of 30 Bcfe were due to decreases in prices for natural gas, NGLs, and oil. Downward revisions of 42 Bcfe were due to an increase in fee structure resulting from the deconsolidation of Antero Midstream Partners. Deconsolidation of Antero Midstream Partners resulted in Antero Resources recording the full fees paid to Antero Midstream Partners for services rendered and Antero Resources no longer including future capital expenditures associated with Antero Midstream Partners' assets in future development costs. Prior to deconsolidation, Antero Resources' consolidated reserves included the elimination of full fees paid by Antero Resources to Antero Midstream Partners and the inclusion of the operating costs and capital incurred by Antero Midstream Partners.

During the year ended December 31, 2019, we converted approximately 2,201 Bcfe, or 29%, of our proved undeveloped reserves to proved developed reserves at a total capital cost of approximately $788 million. We spent an additional $316 million on development costs related primarily to drilled and uncompleted wells and properties in the proved undeveloped classification at December 31, 2018, resulting in total development spending of $1.1 billion, as disclosed in Note 21 to the consolidated financial statements included elsewhere in this report. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2019 are approximately $2.6 billion, or $0.37 per Mcfe, over the next five years. Based on strip pricing as of December 31, 2019, we believe that cash flows from operations will be sufficient to finance such future development costs. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also continue drilling our proved undeveloped reserves. See "Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

We maintain a five-year development plan, which is reviewed by our Board of Directors, which supports our corporate production growth target. The development plan is reviewed annually to ensure capital is allocated to the wells that have the highest risk-adjusted rates of return within our inventory of undrilled well locations. As our well economics have changed, we have reallocated five-year capital to areas with expected highest rates of return and optimal lateral lengths. This resulted in the reclassification of 2,300 Bcfe of reserves from proved undeveloped to probable during the year ended December 31, 2019 due to the five-year development rule. Based on our then-current acreage position, strip prices, anticipated well economics, and our development plans at the time these reserves were classified as proved, we believe the previous classification of these locations as proved undeveloped was appropriate.

At December 31, 2019, an estimated 8,500 of our net leasehold acres, containing 227 locations associated with proved undeveloped reserves, are subject to renewal prior to scheduled drilling. Some of these leases have contract renewal options and some will need to be renegotiated. We estimate a potential cost of approximately $21 million to renew the 8,500 acres based upon current leasing authorizations and option to extend payments. Proved undeveloped reserves of 687 Bcfe are related to these leases. Historically, we have had a high success rate in renewing leases, and we expect that we will be able to renew substantially all of the leases underlying this acreage prior to the scheduled drilling dates. Based on our historical success rate in renewing leases, we estimate that we may not be able to renew leases covering approximately 103 Bcfe of these proved undeveloped reserves.

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

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2017, 2018 and 2019 included in this Annual Report on Form 10-K were prepared by our internal reserve engineers in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

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

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

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

Methodology Used to Apply Reserve Definitions

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

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

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

Identification of Potential Well Locations

Our identified potential well locations represent locations to which proved, probable, or possible reserves were attributable based on SEC pricing as of December 31, 2019. We prepare internal estimates of probable and possible reserves but have not included disclosure of such reserves in this Annual Report on Form 10-K.

Production, Revenues, and Price History

Because natural gas, NGLs, and oil are commodities, the prices that we receive for our production are largely a function of market supply and demand. While demand for natural gas in the United States has increased materially since 2000, natural gas and NGLs supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have been used to find and recover large amounts of oil and gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather, and other seasonal conditions. Over or under supply of natural gas, NGLs, or oil can result in substantial price volatility. A substantial or extended decline in commodity prices, or poor drilling results, could have a material adverse effect on our financial position, results of operations, cash flows, quantities of reserves that may be economically produced, and our ability to access capital markets. See "Item 1A. Risk Factors— Natural gas, NGLs, and oil price volatility, or a substantial or prolonged period of low natural gas, NGLs, and oil prices, may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

Operations Data – Exploration and Production and Marketing Segments

The following table sets forth information regarding our production, realized prices, and production costs for the years ended December 31, 2017, 2018 and 2019. For additional information on price calculations, see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year ended December 31,		
	2017	2018	2019
Production data:			
Natural gas (Bcf)	591	710	822
C2 Ethane (MBbl)	10,539	14,221	15,861
C3+ NGLs (MBbl)	25,507	28,913	39,445
Oil (MBbl)	2,451	3,265	3,632
Combined (Bcfe)	822	989	1,175
Daily combined production (MMcfe/d)	2,253	2,709	3,220
Average sales prices before effects of derivative settlements:			
Natural gas (per Mcf)	$ 2.99	$ 3.22	$ 2.74
C2 Ethane (per Bbl)	$ 8.83	$ 12.14	$ 7.85
C3+ NGLs (per Bbl)	$ 30.48	$ 34.76	$ 27.75
Oil (per Bbl)	$ 44.14	$ 57.34	$ 48.88
Combined average sales prices before effects of derivative settlements (per Mcfe)[(1)]	$ 3.34	$ 3.69	$ 3.10
Combined average sales prices after effects of derivative settlements (per Mcfe)[(1)]	$ 3.60	$ 3.94	$ 3.38
Average Costs (per Mcfe)[(2)]:			
Lease operating	$ 0.11	$ 0.14	$ 0.13
Gathering, compression, processing, and transportation	$ 1.75	$ 1.81	$ 1.92
Production and ad valorem taxes	$ 0.11	$ 0.12	$ 0.11
Marketing, net	$ 0.13	$ 0.23	$ 0.22
Depletion, depreciation, amortization, and accretion	$ 0.86	$ 0.85	$ 0.76
General and administrative (excluding equity-based compensation)	$ 0.14	$ 0.13	$ 0.12

(1) Average sales prices shown in the table reflect both the before and after effects of our settled derivatives. Our calculation of such after effects includes gains on settlements of derivatives excluding proceeds from the derivative monetizations in 2017 and 2018. Our hedges do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

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

Productive Wells

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

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

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

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

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

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we own an interest as of December 31, 2019. A majority of our developed acreage is subject to liens securing the Credit Facility. Approximately 70% of our net Marcellus acreage and 71% of our net Utica acreage is held by production. Acreage related to royalty, overriding royalty, and other similar interests is excluded from this table.

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

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

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

Undeveloped Acreage Expirations

The following table sets forth our total gross and net undeveloped acres as of December31, 2019 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates, or unless the leases containing such acreage are extended or renewed.

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

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2017, 2018 and 2019. Gross wells reflect the number of wells in which we own an interest and include historical drilling activity in the Appalachian Basin. Net wells reflect the sum of our working interests in gross wells.

	Year ended December 31,					
	2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net
Marcellus						
Development wells:						
Productive	112	111	136	134	117	116
Dry	—	—	—	—	—	—
Total development wells	112	111	136	134	117	116
Exploratory wells:						
Productive	1	1	2	2	8	8
Dry	—	—	—	—	—	—
Total exploratory wells	1	1	2	2	8	8
Utica						
Development wells:						
Productive	4	4	17	17	6	6
Dry	—	—	—	—	—	—
Total development wells	4	4	17	17	6	6
Exploratory wells:						
Productive	18	18	8	8	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	18	18	8	8	—	—
Total						
Development wells:						
Productive	116	115	153	151	123	122
Dry	—	—	—	—	—	—
Total development wells	116	115	153	151	123	122
Exploratory wells:						
Productive	19	19	10	10	8	8
Dry	—	—	—	—	—	—
Total exploratory wells	19	19	10	10	8	8

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

Delivery Commitments

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

As of December 31, 2019, our firm sales commitments through 2024 included:

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

We utilize a part of our firm transportation capacity to deliver gas and NGLs under the majority of these firm sales contracts. We have firm transportation contracts that require us to either ship products on said pipelines or pay demand charges for shortfalls. The minimum demand fees are reflected in our table of contractual obligations. See “Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations.”

Gathering and Compression

Our exploration and development activities are supported by the natural gas gathering and compression assets of Antero Midstream and by third-party gathering and compression arrangements. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production. Our relationship with Antero Midstream allows us to obtain the necessary gathering and compression capacity for our production and we have leveraged our relationship with Antero Midstream to support our growth. For the years ended December 31, 2018 and 2019, Antero Midstream spent approximately $444 million and $316 million, respectively, on gas gathering and compression infrastructure that services our production. Subject to pre-existing dedications and other third-party commitments, we have dedicated to Antero Midstream substantially all of our current and future acreage in West Virginia and Ohio for gathering and compression services.

As of December 31, 2019, Antero Midstream owned and operated 324 miles of gas gathering pipelines in the Marcellus Shale. We also have access to additional low-pressure and high-pressure pipelines owned and operated by third parties. As of December 31, 2019, Antero Midstream owned and operated 17 compressor stations and we utilized 12 additional third-party compressor stations in the Marcellus Shale. The gathering, compression, and dehydration services provided by third parties are contracted on a fixed-fee basis.

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

Natural Gas Processing

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

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

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

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

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

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

* Anticipated in-service date

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

Transportation and Takeaway Capacity

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

- We have several firm transportation contracts with pipelines that have capacity to deliver natural gas to the Chicago and Michigan markets. The Chicago directed pipelines include the Rockies Express Pipeline ("REX"), the Midwestern Gas Transmission pipeline ("MGT"), the Natural Gas Pipeline Company of America pipeline ("NGPL"), and the ANR Pipeline Company pipeline ("ANR").
    - The firm transportation contract on REX provides firm capacity for 600,000 MMBtu per day and delivers gas to downstream contracts on MGT, NGPL, and ANR. We have 290,000 MMBtu per day of firm transportation on MGT. We have 310,000 MMBtu per day of firm transportation on NGPL. Both of these contracts deliver gas to the Chicago city gate area. In addition, we have 200,000 MMBtu per day of firm transportation on ANR to deliver natural gas to Chicago in the summer and Michigan in the winter. The Chicago and Michigan contracts expire at various dates from 2021 through 2035.
- To access the Gulf Coast market and Eastern Regional markets, we have firm transportation contracts with various pipelines. These contracts include firm capacity on the Columbia Gas Transmission pipeline ("TCO"), Columbia Gulf Transmission pipeline ("Columbia Gulf"), Tennessee Gas Pipeline ("Tennessee"), Energy Transfer Rover Pipeline ("ET Rover"), ANR Pipeline ("ANR-Gulf"), Equitrans pipeline ("EQT"), and DTE Energy's Stonewall Gas Gathering ("SGG") and Appalachia Gathering System ("AGS"). This diverse portfolio of firm capacity gives us the flexibility to move natural gas to the local Appalachia market or other preferred markets with more favorable pricing.
    - We have several firm transportation contracts on TCO for volumes that total to approximately 584,000 MMBtu per day. Of the 584,000 MMBtu per day of firm capacity on TCO, we have the ability to utilize 530,000 MMbtu per day of firm capacity on Columbia Gulf, which provides access to the Gulf Coast markets. These contracts expire at various dates from 2021 through 2058.
    - We have a firm transportation contract with SGG for 900,000 MMBtu per day which transports gas from various gathering system interconnection points and the MarkWest Sherwood plant complex to the TCO WB System. We have a firm transportation contract with TCO to transport natural gas in the western and eastern direction on TCO's WB system. The firm transportation contract on TCO's WB system provides firm capacity in the western direction for 800,000 MMBtu per day. This west directed firm capacity provides access to the local Appalachia market and the Gulf Coast market via the Columbia Gulf or Tennessee pipelines. The firm transportation contract on TCO's WB system also provides firm capacity in the eastern direction, which delivers natural gas to the Cove Point LNG facility, for 330,000 MMBtu per day. These contracts expire at various dates from 2033 through 2038.
    - We have a firm transportation contract for 790,000 MMBtu per day on Tennessee to deliver natural gas from the Broad Run interconnect on TCO's WB system to the Gulf Coast market. This contract expires in 2033.
    - We have a firm transportation contract for 600,000 MMBtu per day on ANR-Gulf to deliver natural gas from West Virginia and Ohio to the U.S Gulf Coast market. This contract expires in 2045.
    - We have a firm transportation contract for 800,000 MMBtu per day on the ET Rover Pipeline, which connects the Marcellus and Utica Shales' assets to Midwest and Gulf Coast markets via our existing firm transportation on ANR Chicago and ANR Gulf. This contract expires in 2033.
    - We have firm transportation contracts for 250,000 MMBtu per day on EQT to deliver Marcellus natural gas to Tetco M2 and other various delivery points. These contracts expire at various dates from 2022 through 2025.
    - We have firm transportation contracts for 275,000 MMBtu per day on the DTE AGS to deliver Marcellus natural gas to TETCO M2 and other various local delivery points. These contracts expire in 2023.

  - ○ We have firm transportation contracts for 700,000 MMBtu per day on MXP to deliver 517,000 MMBtu per day to TCO IPP and 183,000 MMBtu per day continues on GXP to Leach, Kentucky and deliver to the U.S. Gulf Coast. These contracts expire in 2033.

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

- ● We have a firm transportation contract for 11,500 Bbl per day on the Sunoco pipeline (or "Mariner East 2") to take ethane from Houston, Pennsylvania to Marcus Hook, Pennsylvania. This contract began November 2018. We also have a firm transportation contract on Mariner East 2 to take a combination of 50,000 Bbl per day of propane and butane from Hopedale, Ohio to Marcus Hook, Pennsylvania, which began February 2019. This contract increases 5,000 Bbl per day each year from 2020 – 2022, resulting in an ultimate total of 65,000 Bbl per day. These contracts expire on the tenth anniversary from the in-service date. Mariner East 2 provides access to international markets via trans-ocean LPG carriers.

Under firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations" for information on our minimum fees for such contracts. Based on current projected 2020 annual production guidance, we estimate that we could incur annual net marketing costs of $0.10 per Mcfe to $0.12 per Mcfe in 2020 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third party gas and capture positive basis differentials. Where permitted, we continue to actively market any excess capacity in order to offset minimum commitment fees and those activities are recorded in our net marketing expense.

Water Handling and Treatment Operations

On September 23, 2015, we contributed (i) all of the outstanding limited liability company interests of Antero Water LLC to Antero Midstream and (ii) all of the assets, contracts, rights, permits and properties we owned or leased and used primarily in connection with the construction, ownership, operation, use or maintenance of our advanced wastewater treatment facility in Doddridge County, West Virginia, to Antero Treatment LLC, a wholly owned subsidiary of Antero Midstream. Our relationship with Antero Midstream allows us to obtain the necessary raw fresh and recycled water (collectively, "fresh water") for use in our drilling and completion operations, as well as services to dispose of wastewater resulting from our operations.

Antero Midstream owns two independent fresh water distribution systems that distribute fresh water from the Ohio River and several regional water sources, for well completion operations in the Marcellus and Utica Shales. These systems consist of permanent buried pipelines, movable surface pipelines and fresh water storage facilitates, as well as pumping stations to transport the fresh water throughout the pipeline networks. To the extent necessary, the surface pipelines are moved to well pads for service completion operations in concert with our drilling program. As of December 31, 2019, Antero Midstream had the ability to store 5.8 million barrels of fresh water in 38 impoundments located throughout our leasehold acreage in the Marcellus and Utica Shales. Due to the extensive geographic distribution of Antero Midstream's water pipeline systems in both West Virginia and Ohio, it is able to provide water delivery services to neighboring oil and gas producers within and adjacent to our operating area, subject to commercial arrangements, while reducing water truck traffic.

As of December 31, 2019, Antero Midstream owned and operated 149 miles of buried fresh water pipelines and 98 miles of movable surface fresh water pipelines in the Marcellus Shale, as well as 26 fresh water storage facilities equipped with transfer pumps. As of December 31, 2019, Antero Midstream owned and operated 54 miles of buried fresh water pipelines and 31 miles of movable surface fresh water pipelines in the Utica Shale, as well as 12 fresh water storage facilities equipped with transfer pumps.

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

Major Customers

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

Title to Properties

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

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

Seasonality

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

Competition

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

Regulation of the Oil and Natural Gas Industry

General

Our oil and natural gas operations are subject to extensive, and frequently changing, laws and regulations related to well permitting, drilling, and completion, and to the production, transportation and sale of natural gas, NGLs, and oil. We believe compliance with existing requirements will not have a materially adverse effect on our financial position, cash flows or results of operations. However, such laws and regulations are frequently amended or reinterpreted. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, federal agencies, the states, local governments, and the courts. We cannot predict when or whether any such proposals may become effective. Therefore, we are unable to predict the future costs or impact of compliance. The regulatory burden on the industry increases the cost of doing business and affects profitability. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers, and marketers with which we compete.

Regulation of Production of Natural Gas and Oil

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

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

Regulation of Transportation of Natural Gas

The transportation and sale, or resale, of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or NGPA, and regulations issued under those statutes. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

Gathering services, which occurs upstream of jurisdictional transmission services, are regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although FERC has not made any formal determinations with respect to any of our facilities, we believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Sales of Natural Gas, NGLs, and Oil

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

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

The Domenici Barton Energy Policy Act of 2005, or EPAct of 2005 amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provided FERC with additional civil penalty authority. In Order No. 670, FERC promulgated rules implementing the anti-market manipulation provision of the EPAct of 2005, which make it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704 described below. Under the EPAct of 2005, FERC has the power to assess civil penalties of up to $1,000,000 per day for each violation of the NGA and the NGPA. In January 2020, FERC issued an order (Order No. 865) increasing the maximum civil penalty amounts under the NGA and NGPA to adjust for inflation. FERC may now assess civil penalties under the NGA and NGPA of up to $1,291,894 per violation per day.

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

The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to approximately $2 million (adjusted annually for inflation) per violation per day. Together with FERC, these agencies have imposed broad rules and regulations prohibiting fraud and manipulation in oil and gas markets and energy futures markets.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

General

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

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

Hazardous Substances and Waste Handling

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

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

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

Water Discharges

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

Air Emissions

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

Regulation of "Greenhouse Gas" Emissions

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

In June 2016, the EPA finalized new regulations, known as Subpart OOOOa, that establish emission standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. The EPA's rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rule package extends existing VOC standards under the EPA's Subpart OOOO of the NSPS, or NSPS Quad O, to include previously unregulated equipment within the oil and natural gas source category. Following the change in presidential administrations, there have been attempts to modify these regulations. Most recently, in August 2019, the EPA proposed amendments to the 2016 standards that, among other things, would remove sources in the transmission and storage segment from the oil and natural gas source category and rescind the methane-specific requirements applicable to sources in the production and processing segments of the industry. As an alternative, the EPA also proposed to rescind the methane-specific requirements that apply to all sources in the oil and natural gas industry, without removing the transmission and storage sources from the current source category. Under either alternative, the EPA plans to retain emissions limits for VOCs for covered oil and gas facilities and equipment. Legal challenges to any final rulemaking that rescinds the 2016 standards are expected. As a result of these developments, substantial uncertainty exists with respect to implementation of the EPA's 2016 methane rule. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities.

We have developed a program to reduce and manage our methane and air emissions by: (1) monitoring the science of climate change and air quality, (2) addressing stakeholder inquiries regarding our position on climate change, methane emissions and air quality matters, (3) monitoring our measures to reduce methane and air emissions, and (4) overseeing development of methane and air emission reductions from activities, including implementation of best-management practices and new technology.

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

When we permit a facility, we install air pollution control equipment in an effort to comply with federal Clean Air Act NSPS and applicable Best Available Control Technology standards. The control equipment includes Vapor Recovery Towers (VRTs) and Vapor Recovery Units (VRUs), which capture methane emissions and direct them down a sales line. This technology allows us to recover a valuable product and reduce emissions. Additionally, residual storage tank emissions are controlled with vapor combustors that reduce methane emissions by 98%. We also install low-bleed pneumatic controllers, which minimize methane emissions.

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

In 2017, we joined the EPA Natural Gas Star Program. The EPA Natural Gas STAR Program provides a framework for companies with U.S. oil and gas operations to implement methane reduction technologies and practices and document their emission reduction activities. In 2018, we became members of ONE Future, a voluntary industry collective that seeks to reduce methane emission intensity across the natural gas supply chain. Also in 2018, we began participation in the American Petroleum Institute's The Environmental Partnership, which focuses on voluntary measures that the oil and gas industry can take to reduce emissions of methane and VOCs through the implementation of LDAR, equipment emission monitoring, and maintenance and repair programs.

By joining these programs, we committed to: 1) evaluate our methane emission reduction opportunities, 2) implement methane reduction projects where feasible, and 3) annually report our methane emissions and/or our methane reduction activities.

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

During 2019, our methane emission reduction efforts included the following activities:

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

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

3) Explored the use of lockdown thief hatches on storage tanks.

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

5) Implementation and operation of three stages of pressure control on our storage tanks.

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

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

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

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

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

11) Transition from intermittent bleed to low bleed pneumatics at all new production facilities. We installed air controlled pneumatics on some pads where purchased power was available.

We continue to assess various opportunities for emission reductions. However, we cannot guarantee that we will be able to implement any of the opportunities that we may review or explore. For any such opportunities that we do choose to implement, we cannot guarantee that we will be able to implement them within a specific timeframe or across all operational assets.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States' withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

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

Finally, it should be noted that a number of scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

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

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

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, the Ohio Legislature has adopted a law requiring oil and natural gas operators to disclose chemical ingredients used to hydraulically fracture wells and to conduct pre-drill baseline water quality sampling of certain water wells near a proposed horizontal well. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have banned and others seek to ban hydraulic fracturing altogether. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Occupational Safety and Health Act

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

Endangered Species Act

The federal Endangered Species Act, or ESA, provides for the protection of endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on natural gas and oil leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service, or the USFWS, may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for natural gas and oil development. Moreover, as a result of a settlement, the

USFWS was required to make a determination as to whether more than 250 species classified as endangered or threatened should be listed under the ESA by the completion of the agency's 2017 fiscal year. For example, in April 2015, the USFWS listed the northern long-eared bat, whose habitat includes the areas in which we operate, as a threatened species under the ESA; however, on January 28, 2020, the U.S. District Court for the District of Columbia ordered the USFWS to reconsider its decision to list the northern long-eared bat as threatened instead of endangered. The designation of previously unprotected species as threatened or endangered, or redesignation of a threatened species as endangered, in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2019, nor do we anticipate that such expenditures will be material in 2020.

Employees

As of December 31, 2019, we had 547 full-time employees, including 40 employees in executive, finance, treasury, legal and administration, 20 in information technology, 16 in geology, 219 in production and engineering, 146 in midstream and water, 63 in land, and 43 in accounting and internal audit. Our future success will depend partially on our ability to attract, retain, and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

Address, Internet Website and Availability of Public Filings

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

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

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

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

Item 1A. Risk Factors

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

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

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

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

The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $4.25 per MMBtu to a low of $1.75 per MMBtu in 2019, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $66.24 per barrel to a low of $46.31 per barrel during the same period. In addition, the market price for natural gas in the Appalachian Basin continues to be lower relative to NYMEX Henry Hub as a result of the significant increases in the supply of natural gas in the Northeast region in recent years. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, which adds further volatility to the pricing of NGLs. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas, oil and NGLs at our ultimate sales points and thus cannot predict the ultimate impact of prices on our operations.

Prolonged low, and/or significant or extended declines in, natural gas, NGLs, and oil prices may adversely affect our revenues, operating income, cash flows and financial position, particularly if we are unable to control our development costs during periods of lower natural gas, NGLs, and oil prices. Declines in prices could also adversely affect our drilling activities and the amount of natural gas, NGLs, and oil that we can produce economically, which may result in our having to make significant downward adjustments to the value of our assets and could cause us to incur non-cash impairment charges to earnings in future periods, similar to the $1.0 billion impairment charge we recognized in the third quarter of 2019. Reductions in cash flows from lower commodity prices have required us to incur additional borrowings and reduce our capital spending and could further reduce our production and our reserves, negatively affecting our future rate of growth. Lower prices for natural gas, NGLs, and oil may also adversely affect our credit ratings and result in a reduction in our borrowing capacity and access to other capital. We are also exposed to the risk of non-performance by our hedge counterparties in the event that changes, positive or negative, in natural gas prices result in our derivative contracts having a positive fair value in our favor. Further, adverse economic and market conditions could negatively affect the collectability of our trade receivables and cause our hedge counterparties to be unable to perform their obligations or to seek bankruptcy protection.

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

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

Our future financial condition and results of operations will depend on the success of our exploration, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable hydrocarbons. Our decisions to purchase, explore, or develop prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is subject to operational uncertainties.

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

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

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

Properties that we decide to drill may not yield natural gas or oil in commercially viable quantities.

Properties that we decide to drill that do not yield natural gas or oil in commercially viable quantities may adversely affect our financial condition, results of operations and cash flows. There is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in commercial quantities. We cannot make any assurances that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

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

Market conditions or operational impediments may hinder our access to natural gas, NGLs, and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas, NGLs, and oil transportation arrangements may hinder our access to natural gas, NGLs, and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas, NGLs, and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and other transportation services owned and operated by third parties, including Antero Midstream. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs, and oil pipelines or gathering or processing system capacity or third-party transportation services, including with respect to services provided to us by Antero Midstream. In addition, if natural gas, NGLs, or oil quality specifications for the pipelines with which we connect change so as to restrict our ability to transport our production, our access to natural gas, NGLs, and oil markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

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

At December 31, 2019, 38% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 7.1 Tcfe of estimated proved undeveloped reserves will require an estimated $2.6 billion of development capital over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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

The oil and gas industry is capital intensive. We make, and expect to continue to make, substantial capital expenditures for the exploration, development, production, and acquisition of oil and gas reserves. Our cash flow used in investing activities related to drilling, completions, and land expenditures was approximately $1.3 billion in 2019. Our board of directors has approved a capital budget for 2020 of $1.2 billion that includes $1.15 billion for drilling and completion and $50 million for leasehold expenditures. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations, borrowings under the Credit Facility, our asset sales program and dividends from Antero Midstream; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The actual amount and timing of our future capital expenditures may differ materially from our capital budget as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological, and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. Furthermore, we have previously announced our intention to retire a portion of our outstanding senior notes. Although we intend to finance such retirement primarily with proceeds from asset sales, any borrowings incurred under the Credit Facility for such retirement or other refinancings of debt may limit our ability to fund our capital budget. For additional discussion of the risks regarding our ability to obtain funding, please read "—The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility."

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

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

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

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

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

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

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

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

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

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

The borrowing base under the Credit Facility is currently $4.5 billion, and lender commitments under the Credit Facility are $2.64billion. Our borrowing base is redetermined by the lenders each April based on certain factors, including our reserves and hedge position, with the next borrowing base redetermination scheduled to occur in April 2020. Our borrowing base may decrease as a result of a decline in natural gas, NGLs, or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which could have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

In addition, a downgrade to our corporate credit rating, similar to the December 2019 downgrade by Moody's Investors Services, could require us to post additional collateral in the form of letters of credit or cash as financial assurance of our performance under certain contractual arrangements, such as pipeline transportation contracts. An increase in our outstanding letters of credit may impact our available liquidity under our Credit Facility.

We may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations.

Declines in commodity prices may cause the financial markets to exert downward pressure on stock prices and credit capacity for companies throughout the energy industry. For example, for portions of 2019, the market for senior unsecured notes was unfavorable for high-yield issuers such as us. Our plans for growth may require access to the capital and credit markets, including the ability to issue senior unsecured notes. Although the market for high-yield debt securities experienced periods of improvement in 2019, if the high-yield market deteriorates, or if we are unable to access alternative means of debt or equity financing on acceptable terms, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which could have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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

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

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

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

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

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

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, during 2019, we had estimated average outstanding borrowings under the Credit Facility of approximately $264 million, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased interest expense for that period of approximately $2.6 million and a corresponding decrease in our cash flows and net income before the effects of income taxes. Furthermore, a downgrade to our credit rating would trigger certain obligations to deliver letters of credit to certain transactional counterparties, which would adversely impact our available liquidity. Disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2019, we had entered into forward swap contracts for approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production through December 31, 2023 and basis swap contracts for approximately 0.2 Tcfe through December 31, 2024. Historically, we have realized a significant benefit from our hedge positions. For example, for the years ended December 31, 2018 and 2019, we received approximately $613 million and $325 million, respectively, in revenues from cash settled derivatives pursuant to our hedging arrangements, including $370 million for certain natural gas hedges that were monetized prior to their contractual settlement dates during the year ended December 31, 2018. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2018 and 2019 were executed at times when spot and future prices were higher than prices that we are currently able to obtain in the futures market, and the prices at which we have been able to hedge future production have decreased as a result. Sustained weaknesses in commodity prices adversely affect our ability to hedge future production. If we are unable to enter into new hedge contracts in the future at favorable pricing and for sufficient volumes, our financial condition and results of operations could be materially adversely affected.

Additionally, since we have financial derivatives in place in order to hedge against price declines for a significant part of our estimated future production, we have fixed or limited a significant part of our overall future revenues. Approximately 70% of our estimated production for 2020 is hedged through either forward swaps or basis swaps. If natural gas, NGLs, or oil prices upon settlement of our derivative contracts exceed the price at which we have hedged our commodities, we will be obligated to make cash payments to our hedge counterparties, which could, in certain circumstances, be significant. If development drilling costs increase significantly because of inflation, increased demand for oilfield services, increased costs to comply with regulations governing our industry or other factors, the payments we receive under these derivative contracts may not be sufficient to cover our costs.

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

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

As described above, we enter into certain derivative instruments in the ordinary course operations of our business. Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. Derivative instruments also expose us to the risk of financial loss in some circumstances, including when there is an increase in the differential between the underlying price in the derivative instrument and actual prices received or there are issues with regard to legal enforceability of such instruments.

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

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

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

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

We have various firm transportation and gas processing, gathering and compression service agreements in place, each with minimum volume delivery commitments. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to fully utilize our firm transportation and processing capacity. Our firm transportation agreements expire at various dates from 2021 to 2058, our gas processing, gathering, and compression services agreements expire at various dates from 2020 to 2038. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. As of December 31, 2019, our long-term contractual obligations under agreements with minimum volume commitments totaled over $18 billion over the term of the contracts. If we have insufficient production to meet the minimum volumes, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing, all of which may have a material adverse effect on our results of operations.

Based on current projected 2020 annual production guidance, we estimate that we could incur annual net marketing costs of $0.10 per Mcfe to $0.12 per Mcfe in 2020 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third party gas and capture positive basis differentials. Additionally, our net marketing expense could increase depending on utilization of our transportation capacity based on future production and how much, if any, future excess transportation can be marketed to third parties.

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

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

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

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

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

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

The hydraulic fracture stimulation process on which we depend to produce commercial quantities of natural gas, NGLs, and oil requires the use and disposal of significant quantities of water. The availability of water recycling facilities and other disposal alternatives to receive all of the water produced from our wells may affect our production. For example, Antero Midstream idled its wastewater treatment facility and related landfill in September 2019, which limits Antero Midstream's available outlets to dispose of our produced water. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, or to timely obtain water sourcing permits or other rights, could adversely impact our operations. Additionally, the imposition of new environmental initiatives and regulations could include restrictions on our ability to obtain water or dispose of waste and adversely affect our business and operating results.

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

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

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

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, the Ohio legislature has adopted a law requiring oil and natural gas operators to disclose chemical ingredients used to hydraulically fracture wells and to conduct pre-drill baseline water quality sampling of certain water wells near a proposed horizontal well. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have banned and others seek to ban hydraulic fracturing altogether. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

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

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

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

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

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

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

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

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

As of December 31, 2019, we had 2,385 identified potential horizontal well locations located in our proved, probable, and possible reserve base. As a result of the limitations described above, we may be unable to drill many of our potential well locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to obtain or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified potential well locations, see "Item 1. Business and Properties—Our Properties and Operations—Estimated Proved Reserves—Identification of Potential Well Locations."

Approximately 65% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Approximately 65% of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. We have proved undeveloped reserves of 687 Bcfe related to such acreage that is subject to renewal prior to drilling. In addition, approximately 30% and 29% of our natural gas leases related to our Marcellus and Utica acreage, respectively, require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage. For more information on our future potential acreage expirations, see "Item 1. Business and Properties—Our Properties and Operations—Undeveloped Acreage Expirations."

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

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

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

Our producing properties are geographically concentrated in the Appalachian Basin in West Virginia and Ohio. At December 31, 2019, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by, and costs associated with, governmental regulation, state and local political activities, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of natural gas, NGLs, or oil.

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

Due to the concentrated nature of our portfolio of natural gas properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

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

We have agreements with processing facilities, including those owned by MPLX and the Joint Venture to accommodate our current operations as well as future development plans. Any significant interruptions at these facilities could cause us to curtail our future development and production plans, which could adversely affect our business, financial condition and results of operations.

The operations of the processing facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within the operator's control, such as:

- unscheduled turnarounds or catastrophic events, including damages to facilities, related equipment and surrounding properties caused by earthquakes, tornadoes, hurricanes, floods, fires, severe weather, explosions and other natural disasters;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- disruption in the supply of power, water and other resources necessary to operate the facilities;

- damage to the facilities resulting from NGLs that do not comply with applicable specifications;
- inadequate fractionation capacity or market access to support production volumes, including lack of availability of rail cars, barges, trucks and pipeline capacity, or market constraints, including reduced demand or limited markets for certain NGL products; and
- terrorist or cyber-attacks.

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

Our delivery of natural gas, NGLs, and oil depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing and fractionation facilities and the availability of other third-party transportation services. The capacity of transmission, gathering and processing and fractionation facilities and availability of third-party transportation services may be insufficient to accommodate potential production from existing and new wells, which may result in substantial discounts in the prices we receive for our natural gas, NGLs, and oil. While our investment in midstream infrastructure through Antero Midstream is intended to address access to and potential curtailments on existing midstream infrastructure, we also deliver to and are serviced by third-party natural gas, NGLs, and oil transmission, gathering, processing, storage and fractionation facilities and transportation services that are limited in number, geographically concentrated and subject to significant risks. These risks include the availability of capital, materials and qualified contractors and work force, as well as weather conditions, natural gas, NGLs, and oil price volatility, delays in obtaining permits and other government approvals, title and property access problems, geology, public opposition to infrastructure development, compliance by Antero Midstream and/or third parties with their contractual obligations to us and other factors. An extended interruption of access to or service from pipelines and facilities operated by Antero Midstream and/or third parties, or of transportation services provided by Antero Midstream and/or third parties for any reason, including cyber-attacks on such pipelines and facilities or service interruptions due to gas quality, could result in adverse consequences to us, such as delays in producing and selling our natural gas, NGLs, and oil. In such an event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at prices lower than market prices or at prices lower than we currently project, all of which could adversely affect our business, financial condition and results of operations.

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

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due to the long history of land ownership in the area, resulting in extensive and complex chains of title. Additionally, there are claims against us alleging that certain acquired leases that are held by production are invalid due to production from the producing horizons being insufficient to hold title to the formation rights that we have purchased. The existence of a material title deficiency can render a lease worthless and can adversely affect our financial condition, results of operations and cash flows. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment if the estimated future undiscounted cash flows are less than the carrying value of our properties. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. For example, see the discussion of the impairment charges we recorded in 2018 and 2019 with respect to our Utica Shale properties in Note 2 to the consolidated financial statements. We may incur significant impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

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

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

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

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

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

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through receivables resulting from the sale of our natural gas, NGLs, and oil production that we market to energy companies, end users, and refineries ($297 million at December 31, 2019). We are also subject to credit risk due to concentration of receivables with several significant customers. The largest purchaser of our products during the year ended December 31, 2019 accounted for approximately 16% of our product revenues. We do not require all of our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

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

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

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

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

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

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

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

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

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

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

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

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

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production, processing and transportation of natural gas, NGLs, and oil. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

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

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

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

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

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

Under the EPAct of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1,291,894 per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

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

In June 2016, the EPA finalized new regulations, known as Subpart OOOOa, that establish emission standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. The EPA’s rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rule package extends existing VOC standards under the EPA’s Subpart OOOO to include previously unregulated equipment within the oil and natural gas source category. There have been several attempts to delay or modify these regulations. Most recently, in August 2019, the EPA proposed amendments to the 2016 standards that, among other things, would remove sources in the transmission and storage segment from the oil and gas source category and rescind the methane-specific requirements applicable to sources in the production and processing segments of the industry. As an alternative, the EPA also proposed to rescind the methane-specific requirements that apply to all sources in the oil and gas industry, without removing the transmission and storage sources from the current source category. Under either alternative, the EPA plans to retain emissions limits for VOCs. Legal challenges to any final rulemaking that rescinds the 2016 standards are expected. As a result of the foregoing, substantial uncertainty exists with respect to implementation of the EPA's 2016 methane rule. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a possibility, and several states, including West Virginia and Ohio, have separately imposed or are considering imposing their own regulations on methane emissions from oil and gas production activities.

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

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

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

Separately, increased attention to climate change risks has increased the possibility of claims brought by public and private entities against oil and gas companies in connection with their GHG emissions. While we are not currently party to any such private litigation, we could be named in future actions making similar claims of liability. Moreover, to the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to the company's causation of or contribution to the asserted damage, or to other mitigating factors.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Increased scrutiny because of climate change related concern could result in a loss of certain investors. In addition, institutional lenders may, of their own accord, elect not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

Finally, it should be noted that a number of scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our exploration and production operations.

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

Oil and gas operations in our operating areas can be adversely affected by regulations designed to protect various wildlife. For example, on January 28, 2020, the U.S. District Court for the District of Columbia ordered the USFWS to reconsider its decision to list the northern long-eared bat as threatened instead of endangered. The designation of previously unprotected species as threatened or endangered, or redesignation of a threatened species as endangered, in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in constraints on our exploration and production activities. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

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

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

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

Terrorist or cyber-attacks may significantly affect the energy industry, including our operations and those of our suppliers and customers, as well as general economic conditions, consumer confidence and spending, and market liquidity. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Our insurance may not protect us against such occurrences. We depend on digital technology in many areas of our business and operations, including, but not limited to, estimating quantities of oil and gas reserves, processing and recording financial and operating data, oversight and analysis of drilling operations, and communications with our employees and third-party customers or service providers. Deliberate attacks on our assets, or security breaches in our systems or infrastructure, or the systems or infrastructure of third-parties or the cloud, could lead to the corruption or loss of our proprietary and potentially sensitive data, delays in production or delivery of our production to customers, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, or other operational disruptions and third-party liabilities. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, ransomware, attempts to gain unauthorized access to data and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our 2020 business plan, we considered allocating capital and other resources to various aspects of our businesses, including well development, reserve acquisitions, exploratory activities, midstream infrastructure, corporate items, repayment of indebtedness and other alternatives. We also considered our likely sources of capital, including potential asset sales. Notwithstanding the determinations made in the development of our 2020 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, including the appropriate corporate structure, appropriate rate of reserve development, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2020 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

We periodically engage in acquisitions, dispositions and other strategic transactions, including joint ventures. These transactions involve various inherent risks, such as our ability to obtain the necessary regulatory approvals; the timing of and conditions imposed upon us by regulators in connection with such approvals; the assumption of potential environmental or other liabilities; and our ability to realize the benefits expected from the transactions. In addition, various factors including prevailing market conditions could negatively impact the benefits we receive from transactions. Competition for acquisition opportunities in our industry is intense and may increase the cost of, or cause us to refrain from, completing acquisitions. Joint venture arrangements may restrict our operational and corporate flexibility. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may have little control over, and our joint venture partners may not satisfy their obligations to the joint venture. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our financial position, results of operations and cash flows.

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

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

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

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

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

We are not restricted from issuing additional shares of our common stock out of our authorized capital. In the future, we may issue shares of our common stock to raise cash for future activities, acquisitions or other purposes. We may also acquire interests in other companies by using a combination of cash and shares of our common stock or only shares. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, shares of our common stock. Any of these events may dilute the ownership interests of our stockholders, reduce our earnings per share or have an adverse effect on the price of shares of our common stock.

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

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

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

Certain provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders. Among other things, our certificate of incorporation and bylaws:

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

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

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

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

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

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

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

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

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

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

Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware (the “Court of Chancery”) will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law (the “DGCL”), our certificate of incorporation or our bylaws as to which the DGCL confers jurisdiction on the Court of Chancery or (iv) any action asserting a claim against us governed by the internal affairs doctrine, in each such case subject to the Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring or holding any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of certificate of incorporation described in the preceding sentence. This choice of forum provision may limit our stockholder’s ability to bring a claim in a judicial forum that it finds favorable for disputes with it or its directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition and results of operations.

We have elected not to be subject to the provisions of Section 203 of the DGCL, regulating corporate takeovers.

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

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

Section 203 of the DGCL permits a Delaware corporation to elect not to be governed by the provisions of Section203. Pursuant to our certificate of incorporation, we expressly elected not to be governed by Section 203. Accordingly, we are not subject to any anti-takeover effects or protections of Section 203 of the DGCL, although no assurance can be given that we will not elect to be governed by Section 203 of the DGCL pursuant to an amendment to our certificate of incorporation in the future.

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

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

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

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

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

As of December 31, 2019, we have U.S. federal and state NOL carryforwards of $2.2 billion and $2.0 billion, respectively, some of which expire at various dates from 2032 to 2038 while others have no expiration date. We expect to be able to utilize these NOL carryforwards and generate deductions to offset our future taxable income. This expectation is based upon assumptions we have made regarding, among other things, our income, capital expenditures and net working capital, and the current expectation that our NOL carryforwards will not become subject to future limitations under Section 382 of the Internal Revenue Code of 1986 or otherwise. Additionally, any significant variance in our interpretation of current income tax laws, including as result of the release of final Treasury Regulations or other interpretive guidance implementing the Tax Cuts and Jobs Act, or a challenge of one or more of our tax positions by the IRS or other tax authorities could affect our tax position. While we expect to be able to utilize our NOL carryforwards and generate deductions to offset our future taxable income, in the event that deductions are not generated as expected, one or more of our tax positions are successfully challenged by the IRS (in a tax audit or otherwise), or our NOL carryforwards are subject to future limitations, our future tax liability may be greater than expected.

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

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

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock

We have one class of common equity outstanding, our common stock, par value $0.01 per share. Our common stock is listed on the New York Stock Exchange and traded under the symbol "AR." On February 7, 2020, our common stock was held by 168 holders of record. The number of holders does not include the shareholders for whom shares of our common stock are held in a "nominee" or "street" name.

Issuer Purchases of Equity Securities

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

Period	Total Number of Shares Purchased [(1)]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans [(2)]	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plan
October 1, 2019 - October 31, 2019	3,968	$ 2.65	—	$ 448,351,414
November 1, 2019 - November 30, 2019	7,237,496	$ 2.58	7,237,496	$ 429,683,121
December 1, 2019 - December 31, 2019	1,092,175	$ 2.00	1,092,175	$ 427,503,572
Total	8,333,639	$ 2.50	8,329,671	

(1) The total number of shares purchased includes 3,968 shares repurchased in October 2019, representing shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of restricted stock and restricted stock units held by our employees. There were no such repurchases in November or December.

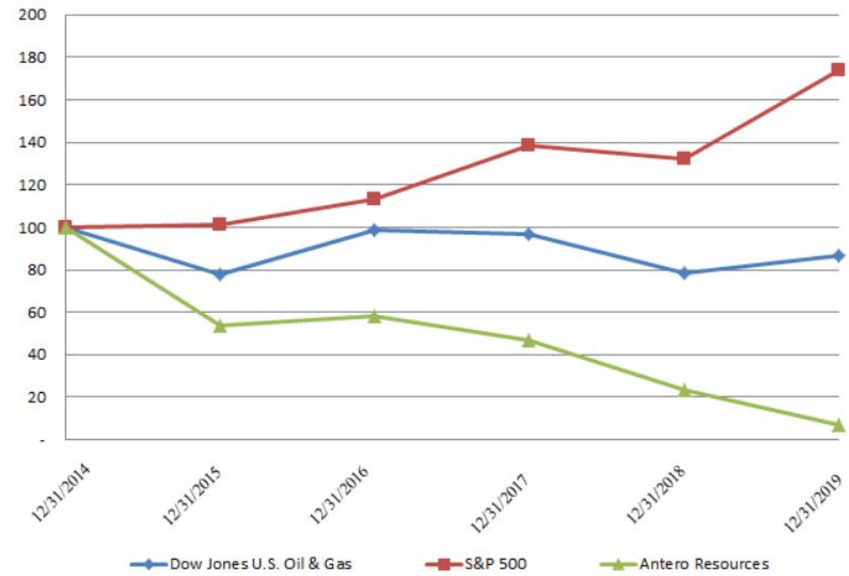
(2) In October 2018, our Board of Directors authorized a $600 million share repurchase program. During the three months ended December 31, 2019, we repurchased 8,329,671 shares of common stock under this program for a total of $21 million, or an average of $2.50 per share, which shares were thereafter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

Dividend Restrictions

Our ability to pay dividends is governed by (i) the provisions of Delaware general corporation law, (ii) our Certificate of Incorporation and Bylaws, (iii) indentures related to our 5.375% senior notes due 2021, 5.125% senior notes due 2022, 5.625% senior notes due 2023, and 5.00% senior notes due 2025 and (iv) the Credit Facility. We have not paid or declared any dividends on our common stock. The future payment of cash dividends on our common stock, if any, is within the discretion of the Board of Directors and will depend on our earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that we will pay any cash dividends on our common stock.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on December 31, 2014 in each of our common stock, the Standard & Poor's 500 ("S&P 500") Index, and the Dow Jones U.S. Oil & Gas Index. We believe the Dow Jones U.S. Oil & Gas Index is meaningful because it is an independent, objective view of the performance of similarly-sized energy companies.



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

Item 6. Selected Financial Data

The following table shows our selected historical consolidated financial data, for the periods ended and as of the dates indicated, for Antero Resources Corporation and its consolidated subsidiaries, including Antero Midstream Partners through March 12, 2019. Effective March 13, 2019, we no longer consolidate Antero Midstream Partners and account for our interest in Antero Midstream using the equity method of accounting. See Note 5 to the consolidated financial statements for further discussion of our equity method investments.

The selected statement of operations data and statement of cash flows data for the years ended December 31, 2017, 2018 and 2019 and the balance sheet data as of December 31, 2018 and 2019 are derived from our audited consolidated financial statements included in Item 8 of this Annual Report on Form 10-K. The selected statement of operations data and statement of cash flows data for the years ended December 31, 2015 and 2016 and the balance sheet data as of December 31, 2015, 2016 and 2017 are derived from our audited consolidated financial statements not included in Item 8 of this Annual Report on Form 10-K.

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

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

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

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

(in thousands, except per share amounts)	Year Ended December 31, 2015	2016	2017	2018	2019
Statement of operations data:					
Operating revenues and other:					
Natural gas sales	$ 1,039,892	1,260,750	1,769,284	2,287,939	2,247,162
Natural gas liquids sales	264,483	432,992	870,441	1,177,777	1,219,162
Oil sales	70,753	61,319	108,195	187,178	177,549
Commodity derivative fair value gains (losses)	2,381,501	(514,181)	658,283	(87,594)	463,972
Gathering, compression, and water handling and treatment	22,000	12,961	12,720	21,344	4,478
Marketing	176,229	393,049	258,045	458,901	292,207
Marketing derivative fair value gains (losses)	—	—	(21,394)	94,081	—
Gain on sale of assets	—	97,635	—	—	—
Other income	—	—	—	—	4,160
Total operating revenues and other	3,954,858	1,744,525	3,655,574	4,139,626	4,408,690
Operating expenses:					
Lease operating	36,011	50,090	89,057	136,153	145,720
Gathering, compression, processing, and transportation	659,361	882,838	1,095,639	1,339,358	2,146,647
Production and ad valorem taxes	78,325	66,588	94,521	126,474	125,142
Marketing	299,062	499,343	366,281	686,055	549,814
Exploration	3,846	6,862	8,538	4,958	884
Impairment of oil and gas properties	104,321	162,935	159,598	549,437	1,300,444
Impairment of midstream assets	—	—	23,431	9,658	14,782
Depletion, depreciation, and amortization	709,763	809,873	824,610	972,465	914,867
Loss on sale of assets	—	—	—	—	951
Accretion of asset retirement obligations	1,655	2,473	2,610	2,819	3,762
General and administrative (including $97,877, $102,421, $103,445, $70,413 and $23,559 of equity-based compensation expense in 2015, 2016, 2017, 2018, and 2019, respectively)	233,697	239,324	251,196	240,344	178,696
Contract termination and rig stacking	38,531	—	—	—	14,026
Total operating expenses	2,164,572	2,720,326	2,915,481	4,067,721	5,395,735
Operating income (loss)	1,790,286	(975,801)	740,093	71,905	(987,045)
Other income (expenses):					
Water earnout	—	—	—	—	125,000
Equity in earnings (loss) of unconsolidated affiliate	—	485	20,194	40,280	(143,216)
Loss on the sale of equity investment shares	—	—	—	—	(108,745)
Interest expense, net	(234,400)	(253,552)	(268,701)	(286,743)	(228,111)
Impairment of equity investments	—	—	—	—	(467,590)
Gain on deconsolidation of Antero Midstream Partners LP	—	—	—	—	1,406,042
Gain (loss) on early extinguishment of debt	—	(16,956)	(1,500)	—	36,419
Total other income (expenses)	(234,400)	(270,023)	(250,007)	(246,463)	619,799
Income (loss) before income taxes	1,555,886	(1,245,824)	490,086	(174,558)	(367,246)
Provision for income tax (expense) benefit	(575,890)	496,376	295,051	128,857	74,110
Net income (loss) and comprehensive income (loss) including noncontrolling interest	979,996	(749,448)	785,137	(45,701)	(293,136)
Net income and comprehensive income attributable to noncontrolling interest	38,632	99,368	170,067	351,816	46,993
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 941,364	(848,816)	615,070	(397,517)	(340,129)
Income (loss) per common share—basic	3.43	(2.88)	1.95	(1.26)	(1.11)
Income (loss) per common share—dilutive	3.43	(2.88)	1.94	(1.26)	(1.11)

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

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

Through March 12, 2019, the financial results of Antero MidstreamPartners were included in our consolidated results. Effective March 13, 2019, we no longer consolidate Antero Midstream Partners and account for our interest in Antero Midstream using the equity method of accounting. See Note 5 to the consolidated financial statements for more information on our equity investments. Adjusted EBITDAX includes distributions received with respect to limited partner interests in Antero Midstream Partners common units through March 12, 2019.

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

- is widely used by investors in the oil and natural gas industry to measure operating performance without regard to items excluded from the calculation of such term, which may vary substantially from company to company depending upon accounting methods and the book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital and legal structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of our operating performance, in presentations to our Board of Directors, and as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by our Board of Directors as a performance measure in determining executive compensation.

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

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

(in thousands)	2015	2016	2017	2018	2019
	Year ended December 31,				
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 941,364	(848,816)	615,070	(397,517)	(340,129)
Net income and comprehensive income attributable to noncontrolling interests	38,632	99,368	170,067	351,816	46,993
Commodity derivative fair value (gains) losses(1)	(2,381,501)	514,181	(658,283)	87,594	(463,972)
Gains on settled commodity derivatives(1)	856,572	1,003,083	213,940	243,112	325,090
Marketing derivative fair value (gains) losses(1)	—	—	21,394	(94,081)	—
Gains on settled marketing derivatives(1)	—	—	—	72,687	—
(Gain) loss on sale of assets	—	(97,635)	—	—	951
Gain on deconsolidation of Antero Midstream Partners LP	—	—	—	—	(1,406,042)
Interest expense	234,400	253,552	268,701	286,743	228,111
(Gain) loss on early extinguishment of debt	—	16,956	1,500	—	(36,419)
Provision for income tax expense (benefit)	575,890	(496,376)	(295,051)	(128,857)	(74,110)
Depletion, depreciation, amortization, and accretion	711,418	812,346	827,220	975,284	918,629
Impairment of oil and gas properties	104,321	162,935	159,598	549,437	1,300,444
Impairment of midstream assets	—	—	23,431	9,658	14,782
Impairment of equity investments	—	—	—	—	467,590
Exploration expense	3,846	6,862	8,538	4,958	884
Equity-based compensation expense	97,877	102,421	103,445	70,413	23,559
Equity in (earnings) loss of unconsolidated affiliate	—	(485)	(20,194)	(40,280)	143,216
Distributions from unconsolidated affiliates	—	7,702	20,195	46,415	157,956
State franchise taxes	72	50	—	—	—
Contract termination and rig stacking	38,531	—	—	—	14,026
Loss on sale of equity investment shares	—	—	—	—	108,745
Water earnout	—	—	—	—	(125,000)
Simplification transaction fees	—	—	—	—	15,482
	1,221,422	1,536,144	1,459,571	2,037,382	1,320,786
Net income and comprehensive income attributable to noncontrolling interests	(38,632)	(99,368)	(170,067)	(351,816)	(46,993)
Antero Midstream Partners interest expense, net(2)	(5,832)	(21,097)	(36,370)	(61,766)	(16,815)
Antero Midstream Partners depreciation, accretion of ARO and accretion of contingent consideration(2)	(71,236)	(116,350)	(133,038)	(37,129)	(21,770)
Antero Midstream Partners impairment(2)	—	—	(23,431)	(5,188)	(6,982)
Antero Midstream Partners equity-based compensation expense(2)	(19,025)	(26,049)	(27,283)	(21,073)	(2,477)
Antero Midstream Partners equity in earnings of unconsolidated affiliates(2)	—	485	20,194	40,280	12,264
Antero Midstream Partners distributions from unconsolidated affiliates(2)	—	(7,702)	(20,195)	(46,415)	(61,319)
Equity in earnings of Antero Midstream Partners(2)	(47,485)	7,156	43,710	3,664	(15,021)
Distributions from Antero Midstream Partners(2)	73,119	107,364	131,598	159,181	95,183
Antero Midstream Partners loss on extinguishment of debt(2)	—	—	(295)	—	—
Antero Midstream Partners gain on sale(2)	—	3,859	—	—	—
Antero Midstream Partners Simplification transaction fees(2)	—	—	—	—	(9,185)
Antero Midstream Partners related adjustments	(109,091)	(151,702)	(215,177)	(320,262)	(73,115)
Adjusted EBITDAX	$ 1,112,331	1,384,442	1,244,394	1,717,120	1,247,671

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

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

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

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

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

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

Our Company

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

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. As of December 31, 2019, we held approximately 451,000 net acres in the southwestern core of the Marcellus Shale, primarily in West Virginia, and approximately 91,000 net acres in the core of the Ohio Utica Shale for a total of 541,000 net acres in the Appalachian Basin. In addition, we estimate that approximately 179,000 net acres of our Marcellus Shale leasehold may be prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on approximately 223,000 net acres of our Marcellus Shale leasehold in West Virginia that may be prospective for the dry gas Utica Shale.

As of December 31, 2019, our estimated proved reserves were approximately 18.9 Tcfe, consisting of 11.5 Tcf of natural gas, 652 MMBbl of assumed recovered ethane, 540 MMBbl of C3+ NGLs, and 42 MMBbl of oil. This represents a 5% increase in estimated proved reserves from December 31, 2018. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2019, we had approximately 2,385 potential horizontal well locations on our existing leasehold acreage that were classified as proved, probable and possible.

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

Closing of Simplification Transaction and Midstream Stock Repurchase

On March 12, 2019, pursuant to the Simplification Agreement, (i) AMGP was converted from a limited partnership to a corporation under the laws of the State of Delaware and changed its name to Antero Midstream Corporation, and (ii) an indirect, wholly owned subsidiary of Antero Midstream was merged with and into Antero Midstream Partners, with Antero Midstream Partners surviving the merger as an indirect, wholly owned subsidiary of Antero Midstream. In connection with the Closing, we received $297 million in cash and 158.4 million shares of Antero Midstream's common stock, par value $0.01 per share, in consideration for 98,870,335 common units representing limited partnership interests in Antero Midstream Partners.

Prior to the Closing, our ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and we consolidated Antero Midstream Partners' financial position and results of operations into our consolidated financial statements. The Transactions resulted in the exchange of limited partner interests in Antero Midstream Partners we owned for common stock of Antero Midstream representing an approximate 31% interest. As a result, we no longer hold a controlling interest in Antero Midstream Partners and now have an interest in Antero Midstream that provides significant influence, but not control, over Antero Midstream. Thus, effective March 13, 2019, we no longer consolidate Antero Midstream Partners in our consolidated financial statements and account for our interest in Antero Midstream using the equity method of accounting. Because Antero Midstream Partners does not meet the requirements of a discontinued operation, Antero MidstreamPartners' results of operations continue to be included in our consolidated statement of operations and comprehensive income (loss) through March 12, 2019.

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

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

Sources of Our Revenues

Our revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our production is entirely from within the continental United States; however, some of our production revenues are attributable to customers who export our products. During 2019, our production revenues were comprised of approximately 62% from the sale of natural gas and 38% from the sale of NGLs and oil. Natural gas, NGLs, and oil prices are inherently volatile and are influenced by many factors outside of our control. All of our production is derived from natural gas wells, some of which also produce NGLs which are extracted through processing, and oil.

To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our production. We enter into primarily fixed price natural gas, NGLs, and oil swap contracts for natural gas in which we receive or pay the difference between a fixed price and the variable market price received, as well as basis swap contracts that hedge the difference between the New York Mercantile Exchange ("NYMEX") index price and a local index price. At the end of each accounting period, we estimate the fair value of these swaps and, because we have not elected hedge accounting, we recognize changes in the fair value of these derivative instruments in earnings. We expect continued volatility in the prices we receive for our production and the fair value of our derivative instruments.

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

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

Principal Components of Our Cost Structure

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

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

- *Production and ad valorem taxes.* Production and ad valorem taxes consist of severance and ad valorem taxes. Severance taxes are paid on produced natural gas and oil based on a percentage of sales prices (not hedged prices) or at fixed per-unit rates established by state authorities. Ad valorem taxes are paid based on the value of our reserves as well as the value of property and equipment.

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

- *Exploration expense.* These are primarily costs related to unsuccessful leasing efforts, as well as geological and geophysical costs, including seismic costs, and costs of unsuccessful exploratory dry holes. We did not record any costs related to exploratory dry holes during the years ended December 31, 2018 and 2019.

- *Impairment of oil and gas properties.* These costs include impairment and costs associated with leases expirations, impairment of design and initial costs related to pads that are no longer planned to be placed into service, and impairment of proved properties due to lower future commodity prices. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks, and future plans to develop the acreage. We also record impairment charges for proved properties on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. We did not record any impairments for proved properties during the year ended December 31, 2018. During the year ended December 31, 2019 the Utica Shale carrying value exceeded the estimated fair value of the Utica Shale assets based on sales of other properties. As a result, we recorded an impairment charge of $881 million related to proved properties in the Utica Shale during the year ended December 31, 2019.

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

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

- *Interest expense.* We finance a portion of our capital expenditures, working capital requirements, and acquisitions with borrowings under the Credit Facility, which has a variable rate of interest based on LIBOR or the prime rate. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. At December 31, 2019, we had a fixed interest rate of 5.375% on our 2021 notes having a principal balance of $953 million, a fixed interest rate of 5.125% on our 2022 notes having a principal balance of $923 million, a fixed interest rate of 5.625% on our 2023 notes having a principal balance of $750 million, and a fixed interest rate of 5.00% on our 2025 notes having a principal balance of $600 million.

- *Income tax expense.* We are subject to state and federal income taxes but are currently not in a cash tax paying position with respect to federal income taxes. The difference between our financial statement income tax expense and our federal income tax liability is primarily due to the differences in the tax and financial statement treatment of oil and gas properties, the effects of noncontrolling interests, and the deferral of unsettled commodity derivative gains for tax purposes until they are settled. We do pay some state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We have recorded deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income primarily from derivatives, oil and gas properties, and NOL carryforwards. At December 31, 2019, we had U.S. federal and state NOL carryforwards of approximately $2.2 billion and $2.0 billion, respectively, some of which expire at various dates between 2032 and 2038 while others have no expiration date. We recorded valuation allowances for deferred tax assets at December 31, 2019 of approximately $47 million related to state loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or as estimates of future taxable income are reduced.

Results of Operations

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

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

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

	Exploration and production	Marketing	Midstream	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2018:					
Revenue and other:					
Natural gas sales	$ 2,287,939	—	—	—	2,287,939
Natural gas liquids sales	1,177,777	—	—	—	1,177,777
Oil sales	187,178	—	—	—	187,178
Commodity derivative fair value losses	(87,594)	—	—	—	(87,594)
Gathering, compression, and water handling and treatment	—	—	1,027,939	(1,006,595)	21,344
Marketing	—	458,901	—	—	458,901
Marketing derivative fair value gains	—	94,081	—	—	94,081
Gain on sale of assets	—	—	583	(583)	—
Other income (expense)	(87,472)	—	—	87,472	—
Total	$ 3,477,828	552,982	1,028,522	(919,706)	4,139,626
Operating expenses:					
Lease operating	$ 142,234	—	262,704	(268,785)	136,153
Gathering, compression, processing, and transportation	1,792,898	—	49,550	(503,090)	1,339,358
Production and ad valorem taxes	122,305	—	4,169	—	126,474
Marketing	—	686,055	—	—	686,055
Exploration	4,958	—	—	—	4,958
Impairment of oil and gas properties	549,437	—	—	—	549,437
Impairment of midstream assets	—	—	9,658	—	9,658
Accretion of asset retirement obligations	2,684	—	135	—	2,819
Depletion, depreciation, and amortization	841,645	—	130,820	—	972,465
General and administrative (excluding equity-based compensation)	131,964	—	40,556	(2,590)	169,930
Equity-based compensation	49,341	—	21,073	—	70,414
Change in fair value of contingent acquisition consideration	—	—	(93,019)	93,019	—
Total	3,637,466	686,055	425,646	(681,446)	4,067,721
Operating income (loss)	$ (159,638)	(133,073)	602,876	(238,260)	71,905
Equity in earnings of unconsolidated affiliates	$ —	—	40,280	—	40,280

		Exploration and production	Marketing	Equity Method Investment in Antero Midstream Corporation	Elimination of intersegment transactions and unconsolidated affiliates	Consolidated total
Year ended December 31, 2019:						
Revenue and other:						
Natural gas sales	$	2,247,162	—	—	—	2,247,162
Natural gas liquids sales		1,219,162	—	—	—	1,219,162
Oil sales		177,549	—	—	—	177,549
Commodity derivative fair value gains		463,972	—	—	—	463,972
Gathering, compression, and water handling and treatment		—	—	849,598	(845,120)	4,478
Marketing		—	292,207	—	—	292,207
Other income (loss)		5,812	—	(57,010)	55,358	4,160
Total	$	4,113,657	292,207	792,588	(789,762)	4,408,690
Operating expenses:						
Lease operating	$	146,990	—	162,376	(163,646)	145,720
Gathering, compression, processing, and transportation		2,257,099	—	41,013	(151,465)	2,146,647
Production and ad valorem taxes		124,202	—	3,830	(2,890)	125,142
Marketing		—	549,814	—	—	549,814
Exploration		884	—	—	—	884
Impairment of oil and gas properties		1,300,444	—	—	—	1,300,444
Impairment of midstream assets		—	—	776,832	(762,050)	14,782
Depletion, depreciation, and amortization		893,161	—	95,526	(73,820)	914,867
Loss on sale of assets		951	—	—	—	951
Accretion of asset retirement obligations		3,699	—	187	(124)	3,762
General and administrative (excluding equity-based compensation)		139,320	—	44,596	(28,779)	155,137
Equity-based compensation		21,082	—	73,517	(71,040)	23,559
Change in fair value of contingent acquisition consideration		—	—	8,076	(8,076)	—
Contract termination and rig stacking		14,026	—	—	—	14,026
Total		4,901,858	549,814	1,205,953	(1,261,890)	5,395,735
Operating income (loss)	$	(788,201)	(257,607)	(413,365)	472,128	(987,045)
Equity in earnings (loss) of unconsolidated affiliates	$	—	—	51,315	(194,531)	(143,216)

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

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

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

(1) Average sales prices shown in the table reflect both the before and after effects of our settled commodity derivatives. Our calculation of such after effects includes gains on settlements of commodity derivatives (but does not include proceeds from derivative monetizations), which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

(2) The average realized price for 2019 includes $54 million of the proceeds related to the South Jersey Litigation. See Note 15 to the consolidated financial statements for further discussion on the South Jersey Litigation. Excluding the effect of the proceeds of the South Jersey Litigation settlement, the average realized price would have been $2.67 per Mcf.

Natural gas sales. Revenues from sales of natural gas remained relatively constant with a decrease of $41 million over the prior year, or 2%. Increased natural gas production volumes accounted for an approximate $358 million increase in year-over-year natural gas sales (calculated as the change in year-to-year volumes times the prior year average price), and decreases in our prices, excluding the effects of derivative settlements, accounted for an approximate $399 million decrease in year-over-year gas sales revenue (calculated as the change in the year-to-year average price times current year production volumes).

NGLs sales. Revenues from sales of NGLs increased $41 million, or 4%. An increase in NGLs production volumes accounted for an approximate $386 million increase in year-over-year NGLs sales revenues (calculated as the change in year-to-year volumes times the prior year average price), and changes in our prices, excluding the effects of derivative settlements, accounted for an approximate $345 million decrease in year-over-year product revenues (calculated as the change in the year-to-year average price times current year production volumes).

Oil sales. Revenues from production of oil decreased from $187 million for the year ended December 31, 2018 to $178 million for the year ended December 31, 2019, a decrease of $10 million, or 5% due to increases in production offset by a decrease in prices.

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

Commodity derivative fair value gains (losses). To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into fixed for variable price swap contracts, basis swap contracts and collar contracts when management believes that favorable future sales prices for our production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment. Consequently, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. For the years ended December 31, 2018 and 2019, our commodity hedges resulted in derivative fair value losses of $88 million and derivative fair value gains of $464 million, respectively. The commodity derivative fair value gains (losses) included $243 million and $325 million of cash proceeds on gains on settled derivatives for the years ended December 31, 2018 and 2019, respectively. Commodity derivative fair value gains (losses) for the years ended December 31, 2018 also include cash proceeds of $370 million related to derivatives that were monetized prior to their contractual settlement dates.

Commodity derivative fair value gains or losses vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled or monetized prior to settlement. Derivative asset or liability positions at the end of any accounting period may reverse to the extent future commodity prices increase or decrease from their levels at the end of the accounting period, or as gains or losses are realized through settlement. We expect continued volatility in commodity prices and the related fair value of our derivative instruments in the future.

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

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

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

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

Impairment of oil and gas properties. Impairment of oil and gas properties increased from $549 million for the year ended December 31, 2018 to $1.3 billion for the year ended December 31, 2019 primarily due to impairment of proved properties in the Ohio Utica Shale. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks, and future plans to develop the acreage.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties. The carrying amount of the Utica Shale exceeded the estimated undiscounted future cash flows based on future strip commodity prices at September 30, 2019. We estimated the fair value of the Utica Shale assets based on sales of other properties. As a result, the Company recorded an impairment charge of $881 million related to proved properties in the Utica Shale during the year ended December 31, 2019.

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

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

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

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

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

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

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

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

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

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

Throughout 2018 and during the period from January 1, 2019 through March 12, 2019, the results of Antero Midstream Partners were included in our consolidated financial statements. Effective March 13, 2019, the results of Antero Midstream Partners were no longer consolidated in our results. See Note 3 to the consolidated financial statements for further discussion on the Transactions. We now account for our interest in Antero Midstream Corporation as an equity method investment.

Antero Midstream Corporation. Revenue from the Antero Midstream Corporation segment decreased from $1.0 billion for the year ended December 31, 2018, to $793 million, which included amortization of customer relationships of $57 million, for the year ended December 31, 2019, a decrease of $236 million, or 23%. The decrease in operating revenue was primarily due to a decrease in fresh water deliveries, which was partially offset by an increase in other fluid handling services for the year ended December 31, 2019. Total operating expenses related to the segment increased from $426 million for the year ended December 31, 2018 to $1.2 billion for the year ended December 31, 2019. The increase was primarily due impairments of $463 million on Antero Midstream's wastewater treatment facility, related goodwill and customer relationships, and $298 million related to the water handling segment goodwill as a result of the annual impairment test.

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

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

Water earnout. In conjunction with the acquisition of the water handling and treatment assets, Antero Midstream agreed to pay us (a) $125 million in cash if Antero Midstream delivered 176 million barrels or more of fresh water during the period between January 1, 2017 and December 31, 2019 and (b) an additional $125 million in cash if Antero Midstream delivers 219 million barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. As of December 31, 2019, Antero Midstream had delivered more than the 176 million barrels, which entitled us to $125 million pursuant to clause (a) above, and, as a result, we recognized other income associated with the settlement on the water earnout. The cash proceeds were received in January 2020.

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

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

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

At December 31, 2018 and December 31, 2019, we had U.S. federal and state NOL carryforwards of approximately $2.2 billion and $2.0, respectively. Many of these NOLs expire at various dates between 2032 and 2038 while others have no expiration date. Future interpretations relating to the passage of the Tax Cuts and Jobs Act that vary from our current interpretation, and possible changes to state tax laws in response to the recently enacted federal legislation, may have a significant effect on our future taxable position. The impact of any such change would be recorded in the period in which such interpretation is received or legislation is enacted.

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

Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2018 for a discussion of the results of operations for the year ended December 31, 2017 compared to the year ended December 31, 2018.

Capital Resources and Liquidity

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

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

Based on strip prices as of December 31, 2019, we believe that cash flows from operations will be sufficient to finance such future development costs. For a discussion of the risks related to development of our proved undeveloped reserves, see "Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

In addition, we may from time to time repurchase shares of our common stock under our share repurchase program. Under our share repurchase program, we repurchased and retired 13,390,617 common shares for $39 million during the year ended December 31, 2019. We may also seek to retire or purchase our outstanding debt securities from time to time through cash purchases, in open market purchases, privately negotiated transactions or otherwise. Any such repurchases will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors.

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

The Credit Facility has a borrowing base of $4.5 billion and current lender commitments of $2.64billion. The borrowing base is redetermined annually based on certain factors including our reserves, natural gas, NGLs, and oil commodity prices, and the value of our hedge portfolio. The next redetermination of the borrowing base is scheduled to occur in April 2020. For a discussion of the risks of a decrease in the borrowing base under the Credit Facility, see "Item 1A. Risk Factors— The borrowing base under the Credit Facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs. We may also be required to post additional collateral as financial assurance of our performance under certain contractual arrangements, which could adversely impact available liquidity under our Credit Facility."

Our commodity hedge position provides us with additional liquidity as it provides us with the relative certainty of receiving a significant portion of our future expected revenues from operations despite potential declines in the price of natural gas, NGLs, or oil. Our ability to make significant additional acquisitions for cash would require us to utilize borrowings on the Credit Facility or obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. The Credit Facility is funded by a syndicate of 25 banks. We believe that the participants in the syndicate have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of the Credit Facility.

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

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

Based on strip prices as of December 31, 2019, we believe that funds from operating cash flows, available borrowings under the Credit Facility, capital market transactions, distributions/dividends from unconsolidated affiliates and proceeds from our asset sale program will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "—Debt Agreements and Contractual Obligations."

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2017, 2018 and 2019:

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

Our consolidated cash flow statements for the years ended December 31, 2017, 2018 and 2019 includes the cash flows related to Antero Midstream Partners for periods prior to March 13, 2019. Effective March 13, 2019, the Company's cash flows include only the operating, investing and financing activities related to Antero and; therefore, the cash flows for the years ended December 31, 2017, 2018 and 2019 are not representative of our expected future cash flows. See Note 3 to the consolidated financial statements for more information.

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

Cash Flows Provided by Operating Activities

Net cash provided by operating activities was $2.1 billion and $1.1 billion for the years ended December31, 2018 and 2019, respectively. Cash flow from operations decreased from 2018 to 2019 primarily due to an increase in gathering, compression, processing, and transportation costs due to the deconsolidation of Antero Midstream Partners and a $370 million decrease in proceeds from derivative monetizations and settlements of as compared to the prior period.

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

Cash Flows Used in Investing Activities

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

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

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

Our consolidated exploration and production capital budget for 2020 is $1.2billion. Our capital budget may be adjusted as business conditions warrant as the amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels that do not generate an acceptable level of corporate returns, or costs increase to levels that do not generate an acceptable level of corporate returns, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity, and to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in commodity prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows, and other factors both within and outside our control.

Cash Flows Provided by Financing Activities

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

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

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

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

Refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity" in our Annual Report on Form 10-K for the year ended December 31, 2018 for a discussion of the cash flows for the year ended December 31, 2017 compared to the year ended December 31, 2018.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility. The Credit Facility is with a consortium of bank lenders. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our assets and are subject to regular annual redeterminations. At December 31, 2019, the borrowing base was $4.5 billion and lender commitments were $2.64 billion. The next redetermination of the borrowing base is scheduled to occur by the end of April 2020. At December 31, 2019, we had $552 million of borrowings with a weighted average interest rate of 3.28% and $623 million of letters of credit outstanding under the Credit Facility. At December 31, 2018, we had $405 million of borrowings and $685 million of letters of credit outstanding under the Credit Facility, with a weighted average interest rate of 3.95%. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the earliest stated redemption date of any series of Antero's senior notes, then outstanding.

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

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

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

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

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

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

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

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

We were in compliance with the applicable covenants and ratios as of December31, 2018 and December 31, 2019. The actual borrowing capacity available to us may be limited by the financial ratio covenants. At December 31, 2019, our current ratio was 5.25 to 1.0 (based on the $4.5 billion borrowing base under the Credit Facility) and our interest coverage ratio was 5.95 to 1.0.

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

On May 6, 2014, we issued the 2022 notes at par. On September 18, 2014, we issued an additional $500 million of the 2022 notes at 100.5% of par. The 2022 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2022 notes rank pari passu to our other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by our wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2022 notes at any time at redemption prices ranging from 101.281% currently to 100.00% on or after June 1, 2020. If we undergo a change of control followed by a rating decline, the holders of the 2022 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued and unpaid interest.

On March 17, 2015, we issued $750 million of 5.625% senior notes due June 1,2023 (the “2023 notes”) at par. The 2023 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2023 notes rank pari passu to our other outstanding senior notes. The 2023 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by our wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2023 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2023 notes at any time at redemption prices ranging from 102.813% to 100.00% on or after June 1, 2021. If we undergo a change of control followed by a rating decline, the holders of the 2023 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2023 notes, plus accrued and unpaid interest.

On December 21, 2016, we issued $600 million of 5.00% senior notes due March 1, 2025 (the “2025 notes”) at par. The 2025 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2025 notes rank pari passu to our other outstanding senior notes. The 2025 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources’ wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2025 notes is payable on March 1 and September 1 of each year. We may redeem all or part of the 2025 notes at any time on or after March 1, 2020 at redemption prices ranging from 103.750% on or after March 1, 2020 to 100.00% on or after March 1, 2023. In addition, on or before March 1, 2020, we may redeem up to 35% of the aggregate principal amount of the 2025 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.00% of the principal amount of the 2025 notes, plus accrued and unpaid interest. At any time prior to March 1, 2020, we may also redeem the 2025 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2025 notes plus a “make-whole” premium and accrued and unpaid interest. If we undergo a change of control following a ratings decline, the holders of the 2025 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2025 notes, plus accrued and unpaid interest.

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

The senior notes indentures each contain restrictive covenants and restrict our ability to incur additional debt unless a pro forma minimum interest coverage ratio requirement of 2.25:1 is maintained. We were in compliance with such covenants as of December 31, 2018 and 2019.

We may, from time to time, seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions, or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, and other factors. The amounts involved could be material. During the fourth quarter of 2019, we repurchased $225 million principal amount of debt at a 17% weighted average discount, including a portion of our 2021 notes and our 2022 notes. The Company recognized a gain of approximately $36 million on the early extinguishment of the debt repurchased.

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

Contractual Obligations. A summary of our contractual obligations as of December 31, 2019 is provided in the table below. capital contributions to unconsolidated affiliates are excluded from the table as neither the amounts nor the timing of the obligations can be determined in advance.

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

(1) Includes outstanding principal amounts at December 31, 2019. This table does not include future commitment fees, interest expense, or other fees on the Credit Facility because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged. The maturity date of the Credit Facility is the earlier of (i) October 26, 2022 and (ii) the date that is 91 days prior to the earliest stated redemption of any series of our senior notes then outstanding.

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

(3) Includes contracts for services provided by drilling rigs and completion fleets, processing, gathering and compression services agreements, and office and equipment leases that expire at various dates from January 2020 through November 2021. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests. See Note 12 to the consolidated financial statements for more information on our operating and finance leases.

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

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

(6) Contractual commitments for processing, gathering, and compression services agreements represent minimum commitments under long-term agreements not accounted for as leases. This includes fees to be paid to the Joint Venture owned by Antero Midstream and MarkWest. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests. The obligations determined to be leases are included within finance and operating leases in the table above.

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

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. Our more significant accounting policies and estimates include the successful efforts method of accounting for our production activities, estimates of natural gas, NGLs, and oil reserve quantities and Standardized measure of future cash flows, and impairment of proved properties. We provide an expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of our consolidated financial statements. See Note 2 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method

The Company accounts for its natural gas, NGLs, and oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when we determine that the well does not contain reserves in commercially viable quantities. The Company reviews exploration costs related to wells in progress at the end of each quarter and makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. We have not incurred any such charges in the years ended December 31, 2017, 2018 and 2019. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units of production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties with significant acquisition costs are assessed for impairment on a property by property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on, or otherwise attributed to, the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of oil and gas properties related to unproved properties for leases that have expired, or are expected to expire, was $160 million, $549 million, and $393 million for the years ended December 31, 2017, 2018 and 2019, respectively.

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

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

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

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

Impairment of Proved Properties

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. Under GAAP for successful efforts accounting, if the carrying amount exceeds the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties.

We did not record any impairments for proved properties during the years ended December 31, 2017 and 2018. During the year ended December 31, 2019 the Utica Shale carrying value exceeded the estimated fair value of the Utica Shale assets based on sales of other properties. As a result, we recorded an impairment of oil and gas properties of $881 million related to proved properties in the Utica Shale during the year ended December 31, 2019.

Based on current future commodity prices, we currently do not anticipate having to record any impairment charge for our proved properties in the near future. We estimate that if strip prices were to decline by approximately 3.25% per from future pricing levels at December 31, 2019, estimated future net revenues for our Utica properties would approximate the carrying amount of the properties and further evaluation of the fair value of those properties would be required in order to determine if an impairment charge would be necessary under GAAP. For our Marcellus properties, strip pricing would have to decline by more than 3.25% from year-end 2019 levels before further evaluation of those properties would be required in order to determine if an impairment charge would be necessary under GAAP. We are unable, however, to predict commodity prices with any greater precision than the futures market.

Fair Value Measurement

The Financial Accounting Standards Board (the "FASB") Accounting Standards Codification Topic 820,*Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and sets forth disclosure requirements about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., the initial recognition of asset retirement obligations and impairments of long-lived assets). The fair value is the price that we estimate would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value hierarchy is used to prioritize inputs to valuation techniques used to estimate fair value. An asset or liability subject to the fair value requirements is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The highest priority (Level 1) is given to unadjusted quoted market prices in active markets for identical assets or liabilities, and the lowest priority (Level 3) is given to unobservable inputs. Level 2 inputs are data, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly.

We account for our investment in an unconsolidated Antero Midstream under the equity method of accounting. We evaluate our equity method investment for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such investment may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management compares the fair value of the investment to the carrying value of the investment to determine whether potential impairment has occurred. If the fair value is less than the carrying value and management considers the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the financial statements as an impairment loss. See Note 9 to the consolidated financial statements for further discussion on our equity method investments.

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

Income Taxes

We are subject to state and federal income taxes, but are currently not in a cash tax paying position with respect to federal income taxes. The difference between our financial statement income tax expense and our federal income tax liability is primarily due to the differences in the tax and financial statement treatment of oil and gas properties and the utilization of NOL carryforwards. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income, primarily from derivatives, oil and gas properties, and net operating loss carryforwards. We have generated net operating loss carryforwards, some of which expire at various dates from 2032 to 2038 while others have no expiration date, which resulted in the recognition of significant deferred tax assets. We record deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets. We record a deferred income tax benefit to the extent our deferred tax assets exceed our deferred tax liabilities.

We record a valuation allowance when we believe all or a portion of our deferred tax assets will not be realized. In assessing the realizability of our deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred tax assets is dependent upon our ability to generate future taxable income during the periods in which our deferred tax assets are deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment, estimates of which may be imprecise due to unforeseen future events or conditions outside of our control, including changes in commodity prices or changes to tax laws and regulations. The amount of deferred tax assets considered realizable could change based upon the amounts of taxable income actually generated, or as estimates of future taxable income change. As of December 31, 2019, we have recognized a valuation allowance of $47 million for net operating loss carryforwards we do not expect to realize that are primarily attributable to states in which we no longer operate.

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

New Accounting Pronouncements

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

Off-Balance Sheet Arrangements

As of December 31, 2019, we did not have any off-balance sheet arrangements other than contractual commitments for firm transportation, gas processing and fractionation, gathering, and compression services and land payment obligations. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for our commitments under these agreements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Hedging Activities

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

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

Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas, NGLs, and oil price fluctuations. These contracts may include commodity price swaps whereby we will receive a fixed price and pay a variable market price to the contract counterparty, collars that set a floor and ceiling price for the hedged production, or basis differential swaps. These contracts are financial instruments, and do not require or allow for physical delivery of the hedged commodity. At December 31, 2019, our commodity derivatives included fixed price swaps and basis differential swaps at index-based pricing.

At December 31, 2019, we had in place natural gas swaps covering portions of our projected production through 2024. Our commodity hedge position as of December 31, 2019 is summarized in Note 11 to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K. Under the Credit Facility, we are permitted to hedge up to 75% of our projected production for the next 60 months. We may enter into hedge contracts with a term greater than 60 months, and for no longer than 72 months, for up to 65% of our estimated production. Based on our production and our fixed price swap contracts that settled during the year ended December 31, 2019, our revenues would have decreased by approximately $64 million for each $0.10 decrease per MMBtu in natural gas prices and $1.00 decrease per Bbl in oil and NGLs prices, excluding the effects of changes in the fair value of our derivative positions which remain open at December 31, 2019.

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

Mark-to-market adjustments of derivative instruments cause earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled or monetized prior to settlement. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are only impacted when the associated derivative contracts are settled or monetized by making or receiving payments to or from the counterparty. At December 31, 2019, the estimated fair value of our commodity derivative instruments was a net asset of $746 million, comprised of current and noncurrent assets and liabilities. At December 31, 2018, the estimated fair value of our commodity derivative instruments was a net asset of $607 million, comprised of current and noncurrent assets and current liabilities.

By removing price volatility from a portion of our expected production through December 2024, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from the following: commodity derivative contracts ($746 million at December 31, 2019) and the sale of our natural gas, NGLs, and oil production ($297 million at December 31, 2019) which we market to energy companies, end users, and refineries.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of a counterparty to perform under the terms of a derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions that management deems to be competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have commodity hedges in place with 17 different counterparties, 13 of which are lenders under the Credit Facility. The fair value of our commodity net derivative contracts of approximately $746 million at December 31, 2019 included the following derivative assets by bank counterparty: Wells Fargo - $215 million; JP Morgan - $134 million; Morgan Stanley - $121 million; Citigroup - $117 million; Scotiabank - $58 million; Canadian Imperial Bank of Commerce - $44 million; PNC - $29 million; BNP Paribas - $21 million; Natixis - $10 million; and SunTrust $7 million. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the counterparties’ respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2019 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by the Credit Facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2019, we did not have any past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

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

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under the Credit Facility, which has a floating interest rate. The average annual interest rate incurred on the Credit Facility during the year ended December 31, 2019 was approximately 4.16%. We estimate that a 1.0% increase in the applicable average interest rates for the year ended December 31, 2019 would have resulted in an estimated $2.6 million increase in interest expense.

Item 8. Financial Statements and Supplementary Data

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

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures and is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2019 at a level of reasonable assurance.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

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

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

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

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

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

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

Under the supervision of, and with the participation of, our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in *Internal Control—Integrated Framework* in 2013, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management of Antero Resources Corporation concluded that our internal control over financial reporting was effective as of December 31, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019 has been audited by KPMG LLP, an independent registered public accounting firm which also audited our consolidated financial statements as of and for the year ended December 31, 2019, as stated in their report which appears beginning on page F-2 in this Annual Report on Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

Directors and Executive Officers

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

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

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

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

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

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

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

W. Patrick Ash has served as our and Antero Midstream's Senior Vice President - Reserves, Planning and Midstream since June 2019, prior to which he served as our Vice President of Reservoir Engineering and Planning beginning in December 2017 and the same at Antero Midstream beginning with the closing of the Transactions in March 2019. Prior to the Transactions, Mr. Ash served as AMGP's and Antero Midstream Partners' Vice President of Reservoir Engineering and Planning beginning in December 2017. Prior to joining us, Mr. Ash was at Ultra Petroleum for six years in management positions of increasing responsibility, most recently serving as Vice President, Development, including during and after Ultra's bankruptcy proceedings, from which it emerged in 2017. In this position he led the reservoir engineering, geoscience, and corporate engineering groups. From 2001 to 2011 Mr. Ash served in engineering roles at Devon, NFR Energy and Encana. Mr. Ash holds a B.S. in Petroleum Engineering from Texas A&M University and a MBA from Washington University in St. Louis.

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

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

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

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

Benjamin A. Hardesty has served as a director since October 2013. He is Chairman of our Nominating & Governance Committee, and he currently serves as a member of our Compensation Committee and Audit Committee. Mr. Hardesty has been the owner of Alta Energy LLC, a consulting business focused on oil and natural gas in the Appalachian Basin and onshore United States, since May 2010. In May 2010, Mr. Hardesty retired as president of Dominion E&P, Inc., a subsidiary of Dominion Resources Inc. (NYSE: D) engaged in the exploration and production of natural gas in North America, a position he had held since September 2007. Mr. Hardesty joined Dominion in 1995 and served as president of Dominion Appalachian Development, Inc. until 2000 and general manager and vice president—Northeast Gas Basins until 2007. Mr. Hardesty was a member of the board of Directors of Blue Dot Energy Services LLC from 2011 until its sale to B/E Aerospace in 2013. From 1982 to 1995, Mr. Hardesty served successively as vice president, executive vice president and president of Stonewall Gas Company, and from 1978 to 1982, he served as vice president-operations of Development Drilling Corp. Mr. Hardesty received his Bachelor of Science degree from West Virginia University and his Master of Science—Management degree from The George Washington University. Mr. Hardesty served as an active duty officer in the U.S. Army Security Agency. Mr. Hardesty currently serves on the board of directors of KLX Energy Services Inc. Mr. Hardesty is a director emeritus and past president of the West Virginia Oil & Natural Gas Association and past president of the Independent Oil & Gas Association of West Virginia. Additionally, Mr. Hardesty is a trustee and past chairman of the Nature Conservancy of West Virginia and a member of the board of directors of the West Virginia Chamber of Commerce. Mr. Hardesty serves as a member of the Visiting Committee of the Petroleum Natural Gas Engineering Department of the College of Engineering and Mineral Resources at West Virginia University.

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

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

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

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

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

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

McConnell holds a B.A. from The Evergreen State College, a J.D. from Antioch School of Law and LL.M. from Georgetown University Law Center.

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

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

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

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

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

Code of Ethics

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

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2020 Annual Meeting of Stockholders.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

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

(a)(3) Exhibits.

Exhibit Number	Description of Exhibit
2.1	Simplification Agreement, dated as of October 9, 2018, by and among AMGP GP LLC, Antero Midstream GP LP, Antero IDR Holdings LLC, Arkrose Midstream Preferred Co LLC, Arkrose Midstream NewCo Inc., Arkrose Midstream Merger Sub LLC, Antero Midstream Partners GP LLC and Antero Midstream Partners LP (incorporated by reference to Exhibit 2.1 to Antero Midstream GP LP's Current Report on Form 8-K (Commission File No. 001-38075) filed on October 10, 2018).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	Amended and Restated Bylaws of Antero Resources Corporation (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.1	Indenture related to the 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
4.2	Form of 5.375% Senior Note due 2021 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
4.3	First Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.4	Second Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
4.5*	Third Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated November 24, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.6*	Fourth Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated January 21, 2015, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee.
4.7	Fifth Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated March 12, 2019, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.8	Indenture related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.9	Form of 5.125% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.10	First Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of November 24, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on November 26, 2014).
4.11	Second Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of January 21, 2015, by and

Exhibit Number	Description of Exhibit
	among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.6 to the Company's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on January 22, 2015).
4.12	Third Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated March 12, 2019, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.13	Indenture related to the 5.625% Senior Notes due 2023, dated as of March 17, 2015, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on March 18, 2015).
4.14	Form of 5.625% Senior Note due 2023 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 333-164876) filed on March 18, 2015).
4.15	First Supplemental Indenture related to the 5.625% Senior Notes due 2023, dated March 12, 2019, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.16	Indenture related to the 5.0% Senior Notes due 2025, dated as of December 21, 2016, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on December 29, 2016).
4.17	Form of 5.0% Senior Note due 2025 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 333-164876) filed on December 29, 2016).
4.18	First Supplemental Indenture related to the 5.0% Senior Notes due 2025, dated March 12, 2019, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Company’s Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 1, 2019).
4.19	Registration Rights Agreement, dated as of October 16, 2013, by and among Antero Resources Corporation and the owners of the membership interests in Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.20*	Description of Securities Registered Under Section 12 of the Securities Exchange Act of 1934, as amended.
10.1	Contribution Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.2	Amended and Restated Contribution Agreement, dated as of November 10, 2014, by and between Antero Resources Corporation and Antero Midstream Partners LP (incorporated by reference to Exhibit 10.1 to Antero Midstream Partners LP’s Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.3	Agreement and Plan of Merger, dated as of October 1, 2013, by and among Antero Resources Corporation, Antero Resources LLC and Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 333-164876) filed on October 11, 2013).
10.4*	Second Amended and Restated Gathering and Compression Agreement, dated as of December 8, 2019, by and between Antero Resources Corporation and Antero Midstream LLC.
10.5	Second Amended and Restated Right of First Offer Agreement, dated as of February 13, 2018, by and between Antero Resources Corporation and Antero Midstream LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 25, 2018).
10.6	License Agreement, dated as of November 10, 2014, by and between Antero Resources Corporation and Antero Midstream Partners LP (incorporated by reference to Exhibit 10.4 to Antero Midstream Partners LP’s Current Report on Form 8-K (Commission File No. 001-36719) filed on November 17, 2014).
10.7*	Amended and Restated Secondment Agreement, effective as of March 13, 2019, by and between Antero Midstream Corporation, Antero Midstream Partners LP, Antero Midstream Partners GP LLC, Antero Midstream LLC, Antero Water LLC, Antero Treatment LLC and Antero Resources Corporation.
10.8*	Second Amended and Restated Services Agreement, effective as of March 13, 2019, by and among Antero Midstream Partners LP, Antero Midstream Corporation, Antero Midstream Partners GP LLC and Antero Resources Corporation.
10.9**	Amended and Restated Water Services Agreement dated as of February 12, 2019, by and between Antero Resources Corporation and Antero Water LLC (incorporated by reference to Exhibit 10.9 to the Company’s Annual Report on

Exhibit Number	Description of Exhibit
	Form 10-K (Commission File No. 001-36120) filed on February 13, 2019).
10.10	Fifth Amended and Restated Credit Agreement, dated as of October 26, 2017, by and among Antero Resources Corporation, the lenders party thereto, and JPMorgan Chase Bank N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on November 1, 2017).
10.11	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of December 21, 2018 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on December 28, 2018).
10.12*	Lender Certificate, dated October 29, 2019, delivered by Royal Bank of Canada, and agreed to and accepted by JPMorgan Chase Bank, N.A., as Administrative Agent, and Antero Resources Corporation.
10.13*	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of December 20, 2019, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent.
10.14†	Form of Amended and Restated Indemnification Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on April 17, 2018).
10.15†	Antero Resources Corporation Long-Term Incentive Plan, effective as of October 1, 2013 (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (Commission File No. 001-36120) filed on October 11, 2013).
10.16†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 25, 2015).
10.17†	Form of Bonus Stock Grant Notice and Bonus Stock Agreement (Form for Non-Employee Directors) under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 24, 2016).
10.18†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement (Form for Special Retention Awards) under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on February 12, 2016).
10.19†	Global Amendment to Grant Notices and Award Agreements Under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).
10.20†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on July 31, 2019).
10.21	Voting Agreement, dated as of October 9, 2018, by and between Antero Midstream GP LP and Antero Resources Corporation (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 10, 2018).
10.22	Amendment No. 1 to the Voting Agreement by and between Antero Midstream GP LP and Antero Resources Corporation, dated as of March 11, 2019 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on March 13, 2019).
10.23	Stockholders' Agreement, dated as of October 9, 2018, by and among Antero Midstream GP LP, Arkrose Subsidiary Holdings LLC, Warburg Pincus Private Equity X O&G, L.P., Warburg Pincus X Partners, L.P., Warburg Pincus Private Equity VIII, LP, Warburg Pincus Netherlands Private Equity VIII C.V.I, WP-WPVIII Investors, L.P., Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P., Yorktown Energy Partners VII, L.P., Yorktown Energy Partners VIII, L.P., Paul M. Rady, Mockingbird Investment, LLC, Glen C. Warren, Jr. and Canton Investment Holdings LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on October 10, 2018).
10.24	Registration Rights Agreement, dated March 12, 2019, by and among Antero Midstream Corporation, the Company, Arkrose Subsidiary Holdings LLC, Glen C. Warren, Jr., Canton Investment Holdings LLC, Paul M. Rady, Mockingbird Investments, LLC and other holders named therein (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (Commission File No. 001-36120) filed on March 13, 2019).
21.1*	Subsidiaries of Antero Resources Corporation.
23.1*	Consent of KPMG LLP.
23.2*	Consent of KPMG LLP.
23.3*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18

Exhibit Number	Description of Exhibit
	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 21, 2020, for proved reserves as of December 31, 2019.
99.2	Report of DeGolyer and MacNaughton, dated as of January 11, 2019, for proved reserves as of December 31, 2018 (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 13, 2019).
99.3	Report of DeGolyer and MacNaughton, dated as of January 10, 2018, for proved reserves as of December 31, 2017 (incorporated by reference to Exhibit 99.1 to the Company's Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 13, 2018).
99.4*	Financial Statements of Antero Midstream Corporation
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2019, formatted in iXBRL (Inline eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Consolidated Statements of Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document).

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

SIGNATURES

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

ANTERO RESOURCES CORPORATION

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

Date: February 12, 2020

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

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

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Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Antero Resources Corporation:

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

We have audited the accompanying consolidated balance sheets of Antero Resources Corporation and subsidiaries (the Company) as of December 31, 2018 and 2019, the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated Framew*ork (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019 based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Change in Accounting Principle

As discussed in Note 12 to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of Accounting Standards Codification Topic 842, *Leases*.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting within *Item 9A. Controls and Procedures*. Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

Critical Audit Matters

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

Assessment of the adoption of ASC 842, Leases

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

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

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

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

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

As discussed in Note 1 to the consolidated financial statements, the Company calculates depletion expense related to proved oil and gas properties using the units-of-production method. Under such method, capitalized costs are amortized over total estimated proved oil and gas reserves. For the year ended December 31, 2019, the Company recorded depletion expense related to proved oil and gas properties of $884 million. Estimating proved oil and gas reserves requires the expertise of professional petroleum reservoir engineers, who take into consideration forecasted production, operating cost assumptions and forecasted oil and gas prices inclusive of market differentials. The Company's internal reservoir engineers estimate proved oil and gas reserves and the Company engages external reservoir engineering specialists to perform an independent evaluation of those proved oil and gas reserve estimates.

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

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's depletion calculation process, and the estimation of proved oil and gas reserves, including controls related to selection of inputs to the reserves estimate. We evaluated the competence, capabilities, and objectivity of the internal reservoir engineers who estimated the proved oil and gas reserves and the external reservoir engineering specialists engaged by the Company. We analyzed and recalculated the depletion expense for compliance with industry and regulatory standards. We assessed the methodology used by the Company's internal reservoir engineers to estimate proved oil and gas reserves and the methodology used by the external reservoir engineering specialists to evaluate those reserve estimates for compliance with industry and regulatory standards. We compared the forecasted production assumptions used by the internal reservoir engineers to historical production rates. We evaluated the operating cost assumptions utilized by the internal reservoir engineers by comparing them to historical costs. We evaluated the oil and gas prices utilized by the internal reservoir engineers by comparing them to publicly available prices and tested the relevant market differentials. We read and considered the findings of the Company's external reservoir engineering specialists in connection with our evaluation of the Company's reserve estimates.

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

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

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

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

/s/ KPMG LLP

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

Denver, Colorado
February 12, 2020

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

	2018	2019
Assets		
Current assets:		
Accounts receivable	$ 51,073	46,419
Accounts receivable, related parties	—	125,000
Accrued revenue	474,827	317,886
Derivative instruments	245,263	422,849
Other current assets	35,450	10,731
Total current assets	806,613	922,885
Property and equipment:		
Oil and gas properties, at cost (successful efforts method):		
Unproved properties	1,767,600	1,368,854
Proved properties	12,705,672	11,859,817
Water handling and treatment systems	1,013,818	—
Gathering systems and facilities	2,470,708	5,802
Other property and equipment	65,842	71,895
	18,023,640	13,306,368
Less accumulated depletion, depreciation, and amortization	(4,153,725)	(3,327,629)
Property and equipment, net	13,869,915	9,978,739
Operating leases right-of-use assets	—	2,886,500
Derivative instruments	362,169	333,174
Investments in unconsolidated affiliates	433,642	1,055,177
Other assets	47,125	21,094
Total assets	$ 15,519,464	15,197,569
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 66,289	14,498
Accounts payable, related parties	—	97,883
Accrued liabilities	465,070	400,850
Revenue distributions payable	310,827	207,988
Derivative instruments	532	6,721
Short-term lease liabilities	2,459	305,320
Other current liabilities	8,363	6,879
Total current liabilities	853,540	1,040,139
Long-term liabilities:		
Long-term debt	5,461,688	3,758,868
Deferred income tax liability	650,788	781,987
Derivative instruments	—	3,519
Long-term lease liabilities	2,873	2,583,678
Other liabilities	63,098	58,635
Total liabilities	7,031,987	8,226,826
Commitments and contingencies (Notes 14 and 15)		
Equity:		
Stockholders' equity:		
Preferred stock, $0.01 par value; authorized - 50,000 shares; none issued	—	—
Common stock, $0.01 par value; authorized - 1,000,000 shares; 308,594 shares and 295,941 shares issued and outstanding at December 31, 2018 and 2019, respectively	3,086	2,959
Additional paid-in capital	6,485,174	6,130,365
Accumulated earnings	1,177,548	837,419
Total stockholders' equity	7,665,808	6,970,743
Noncontrolling interests in consolidated subsidiary	821,669	—
Total equity	8,487,477	6,970,743
Total liabilities and equity	$ 15,519,464	15,197,569

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income (Loss)
Years Ended December 31, 2017, 2018 and 2019
(In thousands, except per share amounts)

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

See accompanying notes to consolidated financial statements.

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

	Common Stock		Additional paid-in capital	Accumulated earnings	Noncontrolling interests	Total equity
	Shares	Amount				
Balances, December 31, 2016	314,877	$ 3,149	5,299,481	959,995	1,465,953	7,728,578
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,502	15	(18,244)	—	—	(18,229)
Issuance of common units by Antero Midstream Partners LP, net of underwriter discounts and offering costs	—	—	—	—	248,956	248,956
Issuance of common units by Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(15,636)	—	9,691	(5,945)
Sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation, net of tax	—	—	206,486	—	(19,940)	186,546
Equity-based compensation	—	—	93,669	—	9,776	103,445
Net income and comprehensive income	—	—	—	615,070	170,067	785,137
Effects of changes in ownership interests in consolidated subsidiaries	—	—	1,005,196	—	(1,005,196)	—
Distributions to noncontrolling interests	—	—	—	—	(152,352)	(152,352)
Balances, December 31, 2017	316,379	3,164	6,570,952	1,575,065	726,955	8,876,136
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,360	13	(11,504)	—	—	(11,491)
Issuance of common units by Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(16,536)	—	11,007	(5,529)
Repurchases and retirements of common stock	(9,145)	(91)	(128,993)	—	—	(129,084)
Equity-based compensation	—	—	62,618	—	7,796	70,414
Net income (loss) and comprehensive income (loss)	—	—	—	(397,517)	351,816	(45,701)
Effects of changes in ownership interests in consolidated subsidiaries	—	—	8,637	—	(8,637)	—
Distributions to noncontrolling interests	—	—	—	—	(267,271)	(267,271)
Other	—	—	—	—	3	3
Balances, December 31, 2018	308,594	3,086	6,485,174	1,177,548	821,669	8,487,477
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	738	7	(2,371)	—	—	(2,364)
Issuance of common units by Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(85)	—	56	(29)
Repurchases and retirements of common stock	(13,391)	(134)	(38,638)	—	—	(38,772)
Equity-based compensation	—	—	22,457	—	1,102	23,559
Net income (loss) and comprehensive income (loss)	—	—	—	(340,129)	46,993	(293,136)
Distributions to noncontrolling interests	—	—	—	—	(85,076)	(85,076)
Effect of deconsolidation of Antero Midstream Partners LP	—	—	(336,172)	—	(784,744)	(1,120,916)
Balances, December 31, 2019	295,941	$ 2,959	6,130,365	837,419	—	6,970,743

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2017	2018	2019
Cash flows provided by (used in) operating activities:			
Net income (loss) and comprehensive income (loss) including noncontrolling interests	$ 785,137	(45,701)	(293,136)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion	827,220	975,284	918,629
Impairments	183,029	559,095	1,782,816
Commodity derivative fair value (gains) losses	(658,283)	87,594	(463,972)
Gains on settled commodity derivatives	213,940	243,112	325,090
Premium paid on derivative contracts	—	(13,318)	—
Proceeds from derivative monetizations	749,906	370,365	—
Marketing derivative fair value gains	21,394	(94,081)	—
Gains on settled marketing derivatives	—	72,687	—
Deferred income tax benefit	(295,126)	(128,857)	(79,158)
Loss on sale of assets	—	—	951
Equity-based compensation expense	103,445	70,414	23,559
Loss (gain) on early extinguishment of debt	1,500	—	(36,419)
Loss on sale of Antero Midstream Corporation shares	—	—	108,745
Equity in earnings (loss) of unconsolidated affiliates	(20,194)	(40,280)	143,216
Water earnout	—	—	(125,000)
Distributions/dividends of earnings from unconsolidated affiliates	20,195	46,415	157,956
Gain on deconsolidation of Antero Midstream Partners LP	—	—	(1,406,042)
Other	(1,907)	4,681	10,681
Changes in current assets and liabilities:			
Accounts receivable	(5,214)	(15,156)	31,631
Accrued revenue	(38,162)	(174,706)	156,941
Other current assets	(2,755)	(5,817)	(1,025)
Accounts payable including related parties	9,462	9,307	(27,996)
Accrued liabilities	64,862	63,562	(25,762)
Revenue distributions payable	45,628	101,210	(102,839)
Other current liabilities	2,214	(3,823)	4,592
Net cash provided by operating activities	2,006,291	2,081,987	1,103,458
Cash flows provided by (used in) investing activities:			
Additions to proved properties	(175,650)	—	—
Additions to unproved properties	(204,272)	(172,387)	(88,682)
Drilling and completion costs	(1,281,985)	(1,488,573)	(1,254,118)
Additions to water handling and treatment systems	(194,502)	(97,699)	(24,416)
Additions to gathering systems and facilities	(346,217)	(444,413)	(48,239)
Additions to other property and equipment	(14,127)	(7,514)	(6,700)
Investments in unconsolidated affiliates	(235,004)	(136,475)	(25,020)
Proceeds from sale of common stock of Antero Midstream Corporation	—	—	100,000
Proceeds from the Antero Midstream Partners LP Transactions	—	—	296,611
Change in other assets	(12,029)	(3,663)	7,091
Proceeds from asset sales	2,156	—	1,983
Net cash used in investing activities	(2,461,630)	(2,350,724)	(1,041,490)
Cash flows provided by (used in) financing activities:			
Issuance of common units by Antero Midstream Partners LP	248,956	—	—
Proceeds from sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation	311,100	—	—
Repurchases of common stock	—	(129,084)	(38,772)
Issuance of senior notes by Antero Midstream Partners LP	—	—	650,000
Repayment of senior notes	—	—	(191,092)
Borrowings on bank credit facilities, net	90,000	660,379	232,000
Payments of deferred financing costs	(16,377)	(2,169)	(4,547)
Distributions to noncontrolling interests in Antero Midstream Partners LP	(152,352)	(267,271)	(85,076)
Employee tax withholding for settlement of equity compensation awards	(24,174)	(17,020)	(2,389)
Other	(4,983)	(4,539)	(2,560)
Net cash provided by financing activities	452,170	240,296	557,564
Antero Midstream Partners LP cash at deconsolidation	—	—	(619,532)
Net decrease in cash and cash equivalents	(3,169)	(28,441)	—
Cash and cash equivalents, beginning of period	31,610	28,441	—
Cash and cash equivalents, end of period	$ 28,441	—	—

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

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

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements

Years Ended December 31, 2017, 2018 and 2019

(1) Organization

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

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). In the opinion of management, the accompanying consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of December 31, 2018 and 2019, and the results of its operations and its cash flows for the years ended December 31, 2017, 2018 and 2019. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is equal to its comprehensive income or loss. Operating results for the year ended December 31, 2019 are not necessarily indicative of the results that may be expected for the full year because of the impact of fluctuations in prices received for natural gas, NGLs, and oil, natural production declines, the uncertainty of exploration and development drilling results, fluctuations in the fair value of derivative instruments, and other factors.

(b) Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Antero Resources Corporation, its wholly owned subsidiaries, any entities in which the Company owns a controlling interest, and variable interest entities ("VIEs") for which the Company is the primary beneficiary.

Through March 12, 2019, Antero Midstream Partners LP ("Antero Midstream Partners"), a publicly traded limited partnership, was included in the consolidated financial statements of Antero. Prior to the Closing (defined in Note 3 to the consolidated financial statements), our ownership of Antero Midstream Partners common units represented approximately a 53% limited partner interest in Antero Midstream Partners, and we consolidated Antero Midstream Partners' financial position and results of operations into our consolidated financial statements. The Transactions (defined in Note 3 to the consolidated financial statements) resulted in the exchange of the limited partner interest we owned in Antero Midstream Partners for common stock of Antero Midstream Corporation representing an approximate 31% interest as of March 13, 2019. As a result, we no longer hold a controlling interest in Antero Midstream Partners and we now have an interest in Antero Midstream Corporation that provides significant influence, but not control, over Antero Midstream Corporation. Thus, effective March 13, 2019, Antero no longer consolidates Antero Midstream Partners in its consolidated financial statements and accounts for its interest in Antero Midstream Corporation using the equity method of accounting.

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

All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements. The noncontrolling interest in the Company's consolidated financial statements represents the interests in Antero Midstream Partners, which were owned by the public prior to the Transactions, and the incentive distribution rights in Antero Midstream Partners, in both cases during the periods prior to the Transactions. Noncontrolling interests in consolidated subsidiaries is included as a component of equity in the Company's consolidated balance sheets.

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

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

(c) Use of Estimates

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

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

(d) Risks and Uncertainties

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

(e) Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short term nature of these instruments. From time to time, the Company may be in the position of a "book overdraft" in which outstanding checks exceed cash and cash equivalents. The Company classifies book overdrafts in accounts payable and revenue distributions payable within its consolidated balance sheets, and classifies the change in accounts payable associated with book overdrafts as an operating activity within its consolidated statements of cash flows. As of December 31, 2019, the book overdraft included within accounts payable and revenue distributions payable were $7 million and $18 million, respectively. As of December 31, 2018, the book overdraft included within accounts payable and revenue distributions payable were $10 million and $28 million, respectively.

(f) Oil and Gas Properties

The Company accounts for its natural gas, NGLs, and oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if the Company determines that the well does not contain reserves in commercially viable quantities. The Company reviews exploration costs related to wells-in-progress at the end of each quarter and makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. The Company incurred no such charges to expense during the years ended December 31, 2017 and 2018. During the year ended December 31, 2019, we recorded an impairment charge of $26 million for design and initial costs related to pads that are no longer planned to be placed into service. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties are assessed for impairment on a property-by-property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, commodity price outlooks, and future plans to develop acreage, as well as drilling results, and reservoir performance of wells in the area. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on, or otherwise attributed, to the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties was $160 million, $549 million, and $393 million for the years ended December 31, 2017, 2018 and 2019, respectively.

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

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

At December 31, 2019, the Company did not have capitalized costs related to exploratory wells-in-progress that have been deferred for longer than one year pending determination of proved reserves.

The provision for depletion of oil and gas properties is calculated on a geological reservoir basis using the units-of-production method. Depletion expense for oil and gas properties was $694 million, $832 million, and $884 million for the years ended December 31, 2017, 2018 and 2019, respectively.

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

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

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

In December 2019, the Company and Antero Midstream Corporation agreed to extend the initial term of the gathering and compression agreement to 2038 and established a growth incentive fee program whereby low pressure gathering fees will be reduced from 2020 through 2023 to the extent the Company achieves certain volumetric targets.

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

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

Impairment of long-lived assets other than oil and gas properties were $23 million, $10 million and $15 million during the years ended December 31, 2017, 2018 and 2019, respectively, and were associated with midstream assets.

(i) Other Property and Equipment

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

(j) Deferred Financing Costs

Deferred financing costs represent loan origination fees and other initial borrowing costs. Such costs are capitalized and included in Other assets on the consolidated balance sheets if related to the Company's revolving credit facilities, and are included as a reduction to Long-term debt on the consolidated balance sheets if related to the issuance of the Company's senior notes. These costs are amortized over the term of the related debt instrument. The Company charges expense for unamortized deferred financing costs if credit facilities are retired prior to their maturity date. At December 31, 2019, the Company had $7 million of unamortized deferred financing costs included in other long-term assets, and $19 million of unamortized deferred financing costs included as a reduction to long-term debt. The amounts amortized and the write-off of previously deferred debt issuance costs were $13 million, $13 million, and $11 million for the years ended December 31, 2017, 2018 and 2019, respectively.

(k) Derivative Financial Instruments

In order to manage its exposure to natural gas, NGLs, and oil price volatility, the Company enters into derivative transactions from time to time, which may include commodity swap agreements, basis swap agreements, collar agreements, and other similar agreements related to the price risk associated with the Company's production. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent that the counterparty is unable to satisfy its settlement obligations. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative positions.

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

(l) Asset Retirement Obligations

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

(m) Environmental Liabilities

Environmental expenditures that relate to an existing condition caused by past operations, and that do not contribute to current or future revenue generation, are expensed as incurred. Liabilities are accrued when environmental assessments and/or clean up is probable and the costs can be reasonably estimated. These liabilities are adjusted as additional information becomes available or circumstances change. As of December 31, 2018 and 2019, the Company did not have a material amount accrued for any environmental liabilities, nor has the Company been cited for any environmental violations that it believes are likely to have a material adverse effect on its financial position, results of operations, or cash flows.

(n) Natural Gas, NGLs, and Oil Revenues

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

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

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

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

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

(o) Marketing Revenues and Expenses

Marketing revenues are derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties. We retain control of the purchased natural gas and NGLs prior to delivery to the purchaser. We have concluded that we are the principal in these arrangements and therefore we recognize revenue on a gross basis, with costs to purchase and transport natural gas and NGLs presented as marketing expenses. Contracts to sell third party gas and NGLs are generally subject to similar terms as contracts to sell our produced natural gas and NGLs. We satisfy performance obligations to the purchaser by transferring control of the product at the delivery point and recognize revenue based on the price received from the purchaser. Fees generated from the sale of excess firm transportation marketed to third parties are included in revenue.

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

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

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

(q) Concentrations of Credit Risk

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

The Company's sales to major customers (purchases in excess of 10% of total sales) for the years ended December 31, 2017, 2018 and 2019 are as follows:

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

The Company is also exposed to credit risk on its commodity derivative portfolio. Any default by the counterparties to these derivative contracts when they become due could have a material adverse effect on the Company's financial condition and results of operations. The Company has economic hedges in place with 14 different counterparties. The fair value of the Company's commodity net derivative contracts is approximately $746 million at December 31, 2019 and primarily includes the following net asset values by bank counterparty: Wells Fargo - $215 million; JP Morgan - $134 million; Morgan Stanley - $121 million; Citigroup - $117 million; Scotiabank - $58 million; Canadian Imperial Bank of Commerce - $44 million; PNC - $29 million; BNP Paribas - $21 million; Natixis - $10 million; and SunTrust $7 million. The estimated fair value of commodity derivative assets has been risk-adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2019 for each of the European and American banks. The Company believes that all of these institutions currently are acceptable credit risks.

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

(r) Income Taxes

The Company recognizes deferred tax assets and liabilities for temporary differences resulting from net operating loss carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in tax laws or tax rates is recognized in income during the period such changes are enacted. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion, or all, of the deferred tax assets will not be realized.

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

(s) Fair Value Measurements

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

(t) Industry Segments and Geographic Information

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

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

(u) Earnings (loss) Per Common Share

Earnings (loss) per common share—basic for each period is computed by dividing net income (loss) attributable to Antero by the basic weighted average number of shares outstanding during the period. Earnings (loss) per common share—assuming dilution for each period is computed after giving consideration to the potential dilution from outstanding equity awards, calculated using the treasury stock method. The Company includes performance share unit awards in the calculation of diluted weighted average shares outstanding based on the number of common shares that would be issuable if the end of the period was also the end of the performance period required for the vesting of the awards. During periods in which the Company incurs a net loss, diluted weighted average shares outstanding are equal to basic weighted average shares outstanding because the effect of all equity awards is anti-dilutive.

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

	Year ended December 31,		
	2017	**2018**	**2019**
Basic weighted average number of shares outstanding	315,426	316,036	306,400
Add: Dilutive effect of restricted stock units	817	—	—
Add: Dilutive effect of outstanding stock options	—	—	—
Add: Dilutive effect of performance stock units	40	—	—
Diluted weighted average number of shares outstanding	316,283	316,036	306,400
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings per common share [(1)]:			
Restricted stock units	1,521	2,844	2,357
Outstanding stock options	676	626	527
Performance stock units	1,054	1,705	1,443

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

(v) Treasury Share Retirement

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

(w) Recently Issued Accounting Standards

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

(x) Equity-Based Compensation

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

(3) Deconsolidation of Antero Midstream Partners LP

In 2014, the Company formed Antero Midstream Partners to own, operate, and develop midstream energy assets that service Antero's production Antero Midstream Partners' assets consist of gathering systems and compression facilities, water handling and treatment facilities, and interests in processing and fractionation plants, through which it provides services to Antero under long-term, fixed-fee contracts.

On March 12, 2019, Antero Midstream GP LP and Antero Midstream Partners completed (the "Closing") the transactions contemplated by the Simplification Agreement (the "Simplification Agreement"), dated as of October 9, 2018, by and among Antero Midstream GP LP, Antero Midstream Partners and certain of their affiliates, pursuant to which (i) Antero Midstream GP LP was converted from a limited partnership to a corporation under the laws of the State of Delaware and changed its name to Antero Midstream Corporation, and (ii) an indirect, wholly owned subsidiary of Antero Midstream Corporation was merged with and into Antero Midstream Partners, with Antero Midstream Partners surviving the merger as an indirect, wholly owned subsidiary of Antero Midstream Corporation (together, along with the other transactions contemplated by the Simplification Agreement, the "Transactions"). In connection with the Closing, Antero received $297 million in cash and 158.4 million shares of Antero Midstream Corporation's common stock, par value $0.01 per share, in consideration for 98,870,335 common units representing limited partnership interests in Antero Midstream Partners.

Prior to the Closing, the Company's ownership of Antero Midstream Partners common units represented approximately a53% limited partner interest in Antero Midstream Partners, and the Company consolidated Antero Midstream Partners' financial position and results of operations into its consolidated financial statements. The Transactions resulted in the exchange of limited partner interests in Antero Midstream Partners owned by Antero for common stock of Antero Midstream Corporation representing an approximate 31% interest as of March 12, 2019. As a result, the Company no longer held a controlling interest in Antero Midstream Partners and the Company held an interest in Antero Midstream Corporation that provided significant influence, but not control, over Antero Midstream Corporation. Thus, effective March 13, 2019, the Company no longer consolidates Antero Midstream Partners in our consolidated financial statements and accounts for its interest in Antero Midstream Corporation using the equity method of accounting. In addition, the Company recorded a gain on deconsolidation of $1.4 billion calculated as the sum of (i) the cash proceeds received, (ii) the fair value of the Antero Midstream Corporation common stock received at the Closing, and (iii) the elimination of the noncontrolling interest, less the carrying amount of the investment in Antero Midstream Partners. The fair value of Antero's retained equity method investment on March 13, 2019 in Antero Midstream Corporation was $2.0 billion based on the market price of the shares received on March 12, 2019. See Note 5 for further discussion on equity method investments.

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

Summarized Financial Information of Antero Midstream Partners

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

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

(4) Revenue

(a) Disaggregation of Revenue

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

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

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

(b) Transaction Price Allocated to Remaining Performance Obligations

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

(c) Contract Balances

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

(5) Equity Method Investments

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

Prior to March 13, 2019, our consolidated results included two equity method investments held by Antero Midstream Partners: a 15% equity interest in Stonewall Gas Gathering LLC ("Stonewall"), which operates a regional gathering pipeline on which the Company is an anchor shipper, and a 50% interest in the joint venture entered into on February 6, 2017 between Antero Midstream Partners and MarkWest Energy Partners, L.P. ("MarkWest"), a wholly owned subsidiary of MPLX, LP, to develop processing and fractionation assets in Appalachia (the "Joint Venture"). Effective March 13, 2019, the equity in earnings of these investments are accounted for in the equity in earnings of Antero Midstream Corporation.

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

	Stonewall [(1)]	MarkWest Joint Venture	Antero Midstream Corporation [(2)]	Total
Balance at December 31, 2017	$ 67,128	236,174	—	303,302
Investments [(3)]	—	136,475	—	136,475
Equity in net income of unconsolidated affiliates	10,740	29,540	—	40,280
Distributions from unconsolidated affiliates	(9,765)	(36,650)	—	(46,415)
Balance at December 31, 2018	$ 68,103	365,539	—	433,642
Investments [(3)]	—	25,020	—	25,020
Equity in net income (loss) of unconsolidated affiliates	1,894	10,370	(155,480)	(143,216)
Distributions/dividends from unconsolidated affiliates	(3,000)	(9,605)	(145,351)	(157,956)
Return of investment [(4)]	—	—	(208,745)	(208,745)
Impairment [(5)]	—	—	(467,590)	(467,590)
Elimination of intercompany profit	—	—	44,548	44,548
Effects of deconsolidation [(6)]	(66,997)	(391,324)	1,987,795	1,529,474
Balance at December 31, 2019	$ —	—	1,055,177	1,055,177

(1) Distributions are net of operating and capital requirements retained by Stonewall.

(2) As adjusted for the amortization of the difference between the cost of the equity investment in Antero Midstream Corporation and the amount of underlying equity in the net assets of Antero Midstream Partners as of the date of deconsolidation and as adjusted for the return of investment.

(3) Investments in the Joint Venture during the year ended December 31,2019 relate to capital contributions for construction of additional processing facilities.

(4) In December 2019, Antero Midstream Corporation repurchased$100 million of its shares of common stock from the Company resulting in a return of investment. The Company recorded an $109 million loss on investment due to the carrying value exceeding the fair value of the stock repurchased.

(5) Other-than-temporary impairment in Antero Midstream Corporation recorded as of December 31, 2019 to reduce the carrying value to fair value.

(6) Effective March 13, 2019, the equity in earnings of Stonewall and the Joint Venture are accounted for in the equity in earnings of Antero Midstream Corporation.

Summarized Financial Information of Antero Midstream Corporation

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

Balance Sheet

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

Statement of Operations

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

(6) Accrued Liabilities

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

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

(7) Long-Term Debt

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

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

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

(a) Senior Secured Revolving Credit Facility

Antero Resources has a senior secured revolving credit facility (the "Credit Facility") with a consortium of bank lenders.

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

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

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

As of December 31, 2019, Antero Resources had an outstanding balance under the Credit Facility of $552 million with a weighted average interest rate of 3.28%, and outstanding letters of credit of $623 million. As of December 31, 2018, Antero Resources had an outstanding balance under the Credit Facility of $405 million, with a weighted average interest rate of 3.95%, and outstanding letters of credit of $685 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from (i) 0.300% to 0.375% (during any period that is not an Investment Grade Period) of the unused portion based on utilization and (ii) 0.150% to 0.300% (during an Investment Grade Period) of the unused portion based on Antero Resources' credit rating.

(b) 5.375% Senior Notes Due 2021

On November 5, 2013, Antero Resources issued $1 billion of 5.375% senior notes due November 1, 2021 (the "2021 notes") at par. The 2021 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2021 notes rank pari passu to Antero Resources' other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. Antero Resources may redeem all or part of the 2021 notes at any time at a redemption price of 100.00%. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2021 notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2021 notes, plus accrued and unpaid interest.

(c) 5.125% Senior Notes Due 2022

On May 6, 2014, Antero Resources issued $600 million of 5.125% senior notes due December 1, 2022 (the "2022 notes") at par. On September 18, 2014, Antero Resources issued an additional $500 million of the 2022 notes at 100.5% of par. The 2022 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2022 notes rank pari passu to Antero Resources' other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. Antero Resources may redeem all or part of the 2022 notes at any time at redemption prices ranging from 101.281% currently to 100.00% on or after June 1, 2020. If

Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2022 notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued and unpaid interest.

(d) 5.625% Senior Notes Due 2023

On March 17, 2015, Antero Resources issued $750 million of 5.625% senior notes due June 1, 2023 (the "2023 notes") at par. The 2023 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2023 notes rank pari passu to Antero Resources' other outstanding senior notes. The 2023 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2023 notes is payable on June 1 and December 1 of each year. Antero Resources may redeem all or part of the 2023 notes at any time at redemption prices ranging from 102.813% to 100.00% on or after June 1, 2021. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2023 notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2023 notes, plus accrued and unpaid interest.

(e) 5.00% Senior Notes Due 2025

On December 21, 2016, Antero Resources issued $600 million of 5.00% senior notes due March 1, 2025 (the "2025 notes") at par. The 2025 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2025 notes rank pari passu to Antero Resources' other outstanding senior notes. The 2025 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero Resources' wholly owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2025 notes is payable on March 1 and September 1 of each year. Antero Resources may redeem all or part of the 2025 notes at any time on or after March 1, 2020 at redemption prices ranging from 103.750% on or after March 1, 2020 to 100.00% on or after March 1, 2023. In addition, on or before March 1, 2020, Antero Resources may redeem up to 35% of the aggregate principal amount of the 2025 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.00% of the principal amount of the 2025 notes, plus accrued and unpaid interest. At any time prior to March 1, 2020, Antero Resources may also redeem the 2025 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2025 notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Resources undergoes a change of control followed by a rating decline, the holders of the 2025 notes will have the right to require Antero Resources to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2025 notes, plus accrued and unpaid interest.

(f) Treasury Management Facility

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

(g) Debt Repurchase Program

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

(8) Asset Retirement Obligations

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

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

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

Revisions to prior estimates in 2019 are primarily due to a decrease in well lives. Revisions to prior estimates in 2018 are primarily due to an increase in estimated abandonment costs for vertical wells. Asset retirement obligations are included in other liabilities on the Company's consolidated balance sheets.

(9) Equity-Based Compensation

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

Antero Midstream Partner's general partner was authorized to grant up to 10,000,000 common units representing limited partner interests in Antero Midstream Partners under the Antero Midstream Partners LP Long-Term Incentive Plan (the "AMP Plan") to non-employee directors of its general partner and certain officers, employees, and consultants of Antero Midstream Partners and its affiliates (which include Antero Resources). As part of the Transactions, each outstanding phantom units awards under the AMP Plan was assumed by Antero Midstream Corporation and converted into 1.8926 restricted stock units under the Antero Midstream Corporation Long Term Incentive Plan (the "AMC Plan"). Each restricted stock unit award under the AMC Plan represents a right to receive one shares of Antero Midstream Corporation's Common Stock, par value $0.01 per share ("Antero Midstream Corporation Common Stock").

The Company's equity-based compensation expense, by type of award, was as follows for the years ended December 31, 2017, 2018 and 2019 (in thousands):

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

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

Restricted Stock Unit Awards

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

A summary of restricted stock unit award activity for the year ended December 31, 2019 is as follows:

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

Intrinsic values are based on the closing price of Antero Resources' common stock on the referenced dates. As of December 31, 2019, there was $21 million of unamortized equity-based compensation expense related to unvested restricted stock units. That expense is expected to be recognized over a weighted average period of approximately 2.4 years.

Stock Options

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

A summary of stock option activity for the year ended December 31, 2019 is as follows:

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

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

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

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

Performance Share Unit Awards

Performance Share Unit Awards Based on Stock Price Targets

In 2016, the Company granted performance share unit awards ("PSUs") to certain of its executive officers that are based on stock price targets. The vesting of these PSUs is conditioned on the closing price of Antero Resources' common stock achieving specific price thresholds over 10-day periods, subject to the following vesting restrictions: no PSUs may vest before the first anniversary of the grant date; no more than one-third of the PSUs may vest before the second anniversary of the grant date; and no more than two-thirds of the PSUs may vest before the third anniversary of the grant date. Any PSUs which have not vested by the fifth anniversary of the grant date will expire. Expense related to these PSUs is recognized on a graded basis over three years. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period.

Performance Share Unit Awards Based on Total Shareholder Return ("TSR")

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

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

Performance Share Unit Awards Based on TSR and Return on Capital Employed ("ROCE")

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

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

Summary Information for Performance Share Unit Awards

A summary of PSU activity for the year ended December 31, 2019 is as follows:

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

The grant-date fair values of market-based PSUs were determined using Monte Carlo simulations, which use a probabilistic approach for estimating the fair values of the awards. Expected volatilities were derived from the volatility of the historical stock prices of a peer group of similar publicly-traded companies. The risk-free interest rate was determined using the yield available for zero-coupon U.S. government issues with remaining terms corresponding to the service periods of the PSUs. A dividend yield of zero was assumed. The grant-date fair value for the ROCE-based PSUs is based on the closing price of Antero Resources' common stock on the date of the grant, assuming the achievement of the performance condition.

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

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

As of December 31, 2019, there was $17 million of unamortized equity-based compensation expense related to unvested PSUs. That expense is expected to be recognized over a weighted average period of approximately 1.8 years.

Antero Midstream Partners Phantom Unit Awards and Antero Midstream Corporation Restricted Stock Unit Awards

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

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

A summary of phantom unit awards and Antero Midstream Corporation restricted stock unit awards resulting from the conversion activity for the year ended December 31, 2019 is as follows:

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

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

Intrinsic values are based on the closing price of shares of Antero Midstream Corporation's common stock or Antero Midstream Partners' common units, as applicable, on the referenced dates. As of December 31, 2019, there was $6.0 million of unamortized equity-based compensation expense related to unvested phantom unit awards. That expense is expected to be recognized over a weighted average period of approximately 1.7 years.

(10) Financial Instruments

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

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

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

(11) Derivative Instruments

(a) Commodity Derivative Positions

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

The Company was party to various fixed price commodity swap contracts that settled during the years ended December31, 2017, 2018 and 2019. The Company enters into these swap contracts when management believes that favorable future sales prices for the Company's production can be secured. Under these swap agreements, when actual commodity prices upon settlement exceed the fixed price provided by the swap contracts, the Company pays the difference to the counterparty. When actual commodity prices upon settlement are less than the contractually provided fixed price, the Company receives the difference from the counterparty. In addition, the Company has entered into basis swap contracts in order to hedge the difference between the New York Mercantile Exchange ("NYMEX") index price and a local index price.

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

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

The Company's derivative contracts have not been designated as hedges for accounting purposes; therefore, all gains and losses are recognized in the Company's statements of operations.

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

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

As of December 31, 2019, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of the Columbia Gas Transmission pipeline ("TCO") to the NYMEX Henry Hub natural gas price, and NGL basis swap positions, which settle on the pricing index to basis differential of Mont Belvieu Butane to the European Butane CIF ARA natural gas liquids price, were as follows:

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

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

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

(b) Marketing Derivatives

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

The Company determined that these gas purchase and sales agreements should be accounted for as derivatives and measured at fair value at the end of each period. The Company recognized a fair value loss for the year ended December 31, 2017 of $21 million. For the year ended December 31, 2018, the Company recognized a fair value gain of $94 million and realized proceeds of $73 million. There were no marketing derivative fair value gains or losses for the year ended December 31, 2019.

(c) Summary

The following table presents a summary of the fair values of the Company's derivative instruments and where such values are recorded in the consolidated balance sheets as of December 31, 2018 and 2019. None of the Company's derivative instruments are designated as hedges for accounting purposes.

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

The following table presents the gross values of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties, and the resulting net amounts presented in the consolidated balance sheets as of the dates presented, all at fair value (in thousands):

	December 31, 2018			December 31, 2019		
	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets (liabilities) on balance sheet	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets (liabilities) on balance sheet
Commodity derivative assets	$ 658,830	(51,398)	607,432	$ 882,817	(126,794)	756,023
Commodity derivative liabilities	$ (51,930)	51,398	(532)	$ (137,034)	126,794	(10,240)

The following is a summary of derivative fair value gains and losses and where such values are recorded in the consolidated statements of operations for the years ended December 31, 2017, 2018 and 2019 (in thousands):

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

Commodity derivative fair value gains (losses) for the years ended December 31, 2017 and 2018, include gains of $750 million and $370 million, respectively, related to certain natural gas derivatives that were monetized prior to their contractual settlement dates. Proceeds received from the monetizations are classified as operating cash flows on the Company's consolidated statement of cash flows for the years ended December 31, 2017 and 2018. There were no commodity derivatives monetizations in the year ended December 31, 2019.

The 2017 monetizations were effected by reducing the average fixed index prices on certain natural gas swap contracts maturing from 2018 through 2022 while maintaining the total volumes hedged. The 2018 monetizations were affected by the early settlement of April through December 2019 swaps and reducing the average fixed index prices on certain natural gas swap contracts maturing in 2020 while maintaining the total volumes hedged. The April through December 2019 swaps were replaced with collar agreements for which the Company paid a $13 million premium. The Company's commodity derivative position presented in Note 11(a) reflects the volume and adjusted fixed price indices after the monetization.

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

(12) Leases

On February 25, 2016, the FASB issued ASU No. 2016-02, *Leases*, which requires lessees to record lease liabilities and right-of-use assets as of the date of adoption and was incorporated into GAAP as ASC Topic 842. The new lease standard does not substantially change accounting by lessors. The Company adopted the new standard effective January 1, 2019. The Company is a lessee to both operating and finance lease arrangements. The standard resulted in an increase in assets and liabilities related to our operating leases.

The Company leases certain office space, processing plants, drilling rigs and completion services, gas gathering lines, compressor stations, and other office and field equipment. Leases with an initial term of 12 months or less are considered short-term and are not recorded on the balance sheet. Instead, the short-term leases are recognized in expense on a straight-line basis over the lease term.

Most leases include one or more options to renew, with renewal terms that can extend the lease fromone to 20 years or more. The exercise of the lease renewal options are at the Company's sole discretion. The depreciable lives of the leased assets are limited by the expected lease term, unless there is a transfer of title or purchase option reasonably certain of exercise.

Certain of the Company's lease agreements include minimum payments based on a percentage of produced volumes over contractual levels and others include rental payments adjusted periodically for inflation.

The Company has elected the effective date method for adoption of the new leasing standard under Topic 842. This method allows the Company to not make retrospective adjustments for leases that were in effect prior to the adoption date of January 1, 2019 when disclosing comparable prior periods, but instead, account for the prior period leases under Topic 840, which was the guidance in place at the time of the original reporting.

The Company considers all contracts that have assets specified in the contract, either explicitly or implicitly, that the Company has substantially all of the capacity of the asset, and has the right to obtain substantially all of the economic benefits of that asset, without the lessor's ability to have a substantive right to substitute that asset, as leased assets under Topic 842. For any contract deemed to include a leased asset, that asset is capitalized on the balance sheet as a right-of-use asset and a corresponding lease liability is recorded at the present value of the known future minimum payments of the contract using a discount rate on the date of commencement. The leased asset classification is determined at the date of recording as either operating or financing, depending upon certain criteria of the contract.

The discount rate used for present value calculations is the discount rate implicit in the contract. If an implicit rate is not determinable, a collateralized incremental borrowing rate is used at the date of commencement. The Company used the collateralized incremental borrowing rate, adjusted for length of lease term, for all of its present value calculations at the initial adoption of Topic 842. Additionally, as new leases commence or previous leases are modified the discount rate used in the present value calculation is the current period applicable discount rate.

The Company has made an accounting policy election to adopt the practical expedient for combining lease and non-lease components on an asset class basis. This expedient allows the Company to combine non-lease components such as real estate taxes, insurance, maintenance, and other operating expenses associated with the leased premises with the lease component of a lease agreement on an asset class basis when the non-lease components of the agreement cannot be easily bifurcated from the lease payment. Currently, the Company is only applying this expedient to certain office space agreements.

Supplemental Balance Sheet Information Related to Leases

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

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

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

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

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

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

Supplemental Information Related to Leases

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

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

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

Short-term lease costs that are more than one month but less than 12 months are excluded from the above amounts and total $63 million at December 31, 2019.

Supplemental Cash Flow Information Related to Leases

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

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

Maturities of Lease Liabilities

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

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

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

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

Lease Term and Discount Rate

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

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

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

Related party lease disclosure

The Company has a gathering and compression agreement with Antero Midstream Corporation, whereby Antero Midstream Corporation receives a low-pressure gathering fee per Mcf, a high-pressure gathering fee per Mcf, and a compression fee per Mcf, in each case subject to adjustments based on the consumer price index. If and to the extent we request that Antero Midstream Corporation construct new high pressure lines and compressor stations, the gathering and compression agreement contains minimum volume commitments that require Antero Resources to utilize or pay for 75% and 70%, respectively, of the requested capacity of such new construction for 10 years. For the year ended December 31, 2019, gathering and compression fees paid by Antero Resources related to this agreement were $643 million. As of December 31, 2019, $57 million was included within accounts payable, related parties on the Condensed Balance Sheet as due to Antero Midstream Corporation related to this agreement.

(13) Income Taxes

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

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

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

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

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

Deferred income taxes reflect the impact of temporary differences between assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. The tax effect of the temporary differences giving rise to net deferred tax assets and liabilities at December 31, 2018 and 2019 is as follows (in thousands):

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

In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the Company's temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the projections of future taxable income over the periods in which the deferred tax assets are deductible, management believes that the Company will not realize the benefits of certain of these deductible differences and has recorded a valuation allowance of approximately $45 million and $47 million at December 31, 2018 and 2019, respectively, related to state net operating loss ("NOL") carryforwards. The increase in the valuation allowance from $45 million at December 31, 2018 to $47 million at December 31, 2019, is due to an increase in Colorado NOLs, resulting from tax return amendments, against which a full valuation allowance has been previously established. The amount of the deferred tax asset considered realizable could be further reduced in the near term if estimates of future taxable income during the carryforward period are revised.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The Company monitors potential uncertain tax positions but does not anticipate any changes within the next year. The Company has no unrecognized tax benefit balances through December 31, 2019.

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

Tax years 2016 through 2019 remain open to examination by the U.S. Internal Revenue Service. The Company and its subsidiaries file tax returns with various state taxing authorities and those returns remain open to examination for tax years 2015 through 2019.

(14) Commitments

The table below is a schedule of future minimum payments for firm transportation, drilling rig and completion services, processing, gathering and compression, and office and equipment agreements, which include leases that have remaining lease terms in excess of one year as of December 31, 2019 (in thousands).

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

(a) Firm Transportation

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

(b) Processing, Gathering, and Compression Service Commitments

The Company has entered into various long term gas processing, gathering and compression service agreements. Certain of these agreements were determined to be leases. The minimum payment obligations under the agreements that are not leases are presented in this column.

The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(c) Land Payment Obligations

The Company has entered into various land acquisition agreements. Certain of these agreements contain minimum payment obligations over various terms. The values in the table represent the minimum payments due under these arrangements. None of these agreements were determined to be leases.

(d) Leases, including imputed interest

The Company has obligations under contracts for services provided by drilling rigs and completion fleets, processing, gathering, and compression services agreements, and office and equipment leases. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interests. Refer to Note 12 to the consolidated financial statements for more information on the Company's operating and finance leases.

(15) Contingencies

Environmental

In June 2018, following site inspections conducted in September 2017 at certain of our facilities located in Doddridge County, Tyler County, and Ritchie County, West Virginia, we received a Notice of Violation ("NOV") from the U.S. Environmental Protection Agency ("EPA") Region III for alleged violations of the federal Clean Air Act and the West Virginia State Implementation Plan relating to permitting and control requirements for emissions of regulated pollutants at several of our natural gas production facilities. The NOV alleges that combustion devices at these facilities did not meet applicable air permitting requirements. Separately, in June 2018, we received an information request from EPA Region III pursuant to Section 114(a) of the Clean Air Act relating to the facilities that were inspected in September 2017 as well as additional Antero Resources facilities for the purpose of determining if the additional facilities have the same alleged compliance issues that were identified during the September 2017 inspections. We have separately received an NOV from West Virginia Department of Environmental Protection ("WVDEP") alleging violations relating to the same issues being investigated by the EPA. We continue to negotiate with EPA and WVDEP to resolve the issues alleged in the NOVs and the information request; however, we believe that there is a reasonable possibility that these actions may result in monetary sanctions exceeding $100,000. Our operations at these facilities are not suspended, and management does not expect these matters to have a material adverse effect on our financial condition, results of operations, or cash flows.

SJGC

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

WGL

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively, "WGL") were involved in a pricing dispute involving firm gas sales contracts executed June 20, 2014 (the "Contracts") that the Company began delivering gas under in January 2016. From January 2016 through July 2017 and from December 2017 through January 2018, the aggregate daily gas volumes contracted for under the Contracts was 500,000 MMBtu/day, with the aggregate daily contracted volumes having increased to 600,000 MMBtu/day from August through November 2017. The Company invoiced WGL based on the natural gas index price specified in the Contracts and WGL paid the Company based on that invoice price. However, WGL asserted that the index price was no longer appropriate under the Contracts and claimed that an undefined alternative index was more appropriate for the delivery point of the gas. In July 2016, the matter was referred to arbitration by the Colorado district court. In January 2017, the arbitration panel ruled in the Company's favor. As a result, the index price has remained as specified in the Contracts and there will be no adjustments to the invoices that have been paid by WGL, nor will future invoices to WGL be adjusted based on the same claim rejected by the arbitration panel. The arbitration panel's award was confirmed by the Colorado district court on April 14, 2017.

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

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

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

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

Other

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

(16) Contract Termination and Rig Stacking

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

(17) Related Parties

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

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

(18) Segment Information

See Note 2(t) to the consolidated financial statements for a description of the Company's determination of its reportable segments. Revenues from gathering and processing and water handling and treatment operations were primarily derived from intersegment transactions for services provided to the Company's exploration and production operations prior to the closing of the Transactions. Through March 12, 2019, the results of Antero Midstream Partners were included in the consolidated financial statements of Antero Resources. Effective March 13, 2019, the results of Antero Midstream Partners are no longer consolidated in Antero Resources' result; however, the Company's segment disclosures include the results of our unconsolidated affiliates due to their significance to the Company's operations. See Note 3 to the consolidated financial statements for further discussion on the Transactions. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties.

Operating segments are evaluated based on their contribution to consolidated results, which is primarily determined by the respective operating income (loss) of each segment. General and administrative expenses were allocated to the midstream segment based on the nature of the expenses and on a combination of the segments' proportionate share of the Company's consolidated property and equipment, capital expenditures, and labor costs, as applicable. General and administrative expenses related to the marketing segment are not allocated because they are immaterial. Other income, income taxes, and interest expense are primarily managed and evaluated on a consolidated basis. Intersegment sales were transacted at prices which approximate market. Accounting policies for each segment are the same as the Company's accounting policies described in Note 2 to the consolidated financial statements.

The operating results and assets of the Company's reportable segments were as follows for the years ended December 31, 2017, 2018 and 2019 (in thousands):

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

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

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

(19) Condensed Consolidating Financial Information

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

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

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 2,287,939	—	—	—	2,287,939
Natural gas liquids sales	1,177,777	—	—	—	1,177,777
Oil sales	187,178	—	—	—	187,178
Commodity derivative fair value losses	(87,594)	—	—	—	(87,594)
Gathering, compression, water handling and treatment	—	—	1,027,939	(1,006,595)	21,344
Marketing	458,901	—	—	—	458,901
Marketing derivative fair value gains	94,081	—	—	—	94,081
Gain on sale of assets	—	—	583	(583)	—
Other income	(87,217)	—	—	87,217	—
Total revenue and other	4,031,065	—	1,028,522	(919,961)	4,139,626
Operating expenses:					
Lease operating	142,234	—	262,704	(268,785)	136,153
Gathering, compression, processing, and transportation	1,792,898	—	49,550	(503,090)	1,339,358
Production and ad valorem taxes	122,305	—	4,169	—	126,474
Marketing	686,055	—	—	—	686,055
Exploration	4,958	—	—	—	4,958
Impairment of oil and gas properties	549,437	—	—	—	549,437
Impairment of midstream assets	4,470	—	5,771	(583)	9,658
Depletion, depreciation, and amortization	842,452	—	130,013	—	972,465
Accretion of asset retirement obligations	2,684	—	135	—	2,819
General and administrative	181,305	—	61,629	(2,590)	240,344
Accretion of contingent acquisition consideration	—	—	(93,019)	93,019	—
Total operating expenses	4,328,798	—	420,952	(682,029)	4,067,721
Operating income (loss)	(297,733)	—	607,570	(237,932)	71,905
Other income (expenses):					
Equity in earnings of unconsolidated affiliates	—	—	40,280	—	40,280
Interest expense, net	(224,977)	—	(61,906)	140	(286,743)
Equity in earnings (loss) of consolidated subsidiaries	(3,664)	—	—	3,664	—
Total other expenses	(228,641)	—	(21,626)	3,804	(246,463)
Income (loss) before income taxes	(526,374)	—	585,944	(234,128)	(174,558)
Provision for income tax benefit	128,857	—	—	—	128,857
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(397,517)	—	585,944	(234,128)	(45,701)
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	351,816	351,816
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (397,517)	—	585,944	(585,944)	(397,517)

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

	Parent (Antero)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 2,247,162	—	—	—	2,247,162
Natural gas liquids sales	1,219,162	—	—	—	1,219,162
Oil sales	177,549	—	—	—	177,549
Commodity derivative fair value gains	463,972	—	—	—	463,972
Gathering, compression, water handling and treatment	—	—	218,360	(213,882)	4,478
Marketing	292,207	—	—	—	292,207
Other income	5,810	—	—	(1,650)	4,160
Total revenue and other	4,405,862	—	218,360	(215,532)	4,408,690
Operating expenses:					
Lease operating	146,957	—	64,818	(66,055)	145,720
Gathering, compression, processing, and transportation	2,257,133	—	—	(110,486)	2,146,647
Production and ad valorem taxes	124,202	—	—	940	125,142
Marketing	549,814	—	—	—	549,814
Exploration	884	—	—	—	884
Impairment of oil and gas properties	1,300,444	—	—	—	1,300,444
Impairment of midstream assets	7,800	—	6,982	—	14,782
Depletion, depreciation, and amortization	893,160	—	21,707	—	914,867
Loss on sale of assets	951	—	—	—	951
Accretion of asset retirement obligations	3,699	—	63	—	3,762
General and administrative	160,402	—	18,793	(499)	178,696
Contract termination and rig stacking	14,026	—	—	—	14,026
Accretion of contingent acquisition consideration	—	—	1,928	(1,928)	—
Total operating expenses	5,459,472	—	114,291	(178,028)	5,395,735
Operating income (loss)	(1,053,610)	—	104,069	(37,504)	(987,045)
Other income (expenses):					
Water earnout	125,000			—	125,000
Equity in earnings (loss) of unconsolidated affiliates	(49,442)	(106,038)	12,264	—	(143,216)
Equity in earnings of affiliates	15,021	—	—	(15,021)	—
Loss on the sale of equity investment shares	(108,745)	—	—	—	(108,745)
Impairment of equity investments	(143,090)	(324,500)	—	—	(467,590)
Gain on deconsolidation of Antero Midstream Partners LP	1,205,705	200,337	—	—	1,406,042
Interest expense, net	(211,296)	—	(16,815)	—	(228,111)
Gain on early extinguishment of debt	36,419	—	—	—	36,419
Total other income (expenses)	869,572	(230,201)	(4,551)	(15,021)	619,799
Income before income taxes	(184,038)	(230,201)	99,518	(52,525)	(367,246)
Provision for income tax expense	74,110	—	—	—	74,110
Net income (loss) and comprehensive income (loss) including noncontrolling interests	(109,928)	(230,201)	99,518	(52,525)	(293,136)
Net income and comprehensive income attributable to noncontrolling interests	—	—	—	46,993	46,993
Net income and comprehensive income attributable to Antero Resources Corporation	$ (109,928)	(230,201)	99,518	(99,518)	(340,129)

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

(20) Quarterly Financial Information (Unaudited)

The Company's quarterly consolidated financial information for the years ended December31, 2018 and 2019 is summarized in the tables below (in thousands, except per share amounts). The Company's quarterly operating results are affected by the volatility of commodity prices and the resulting effect on our production revenues and the fair value of commodity derivatives.

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

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

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

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

The following is supplemental information regarding the Company's consolidated oil and gas producing activities. The amounts shown include the Company's net working interests in all of its oil and gas properties.

(a) Capitalized Costs Relating to Oil and Gas Producing Activities

		Year ended December 31,	
(In thousands)		**2018**	**2019**
Proved properties	$	12,705,672	11,859,817
Unproved properties		1,767,600	1,368,854
		14,473,272	13,228,671
Accumulated depletion and depreciation		(3,615,680)	(3,284,330)
Net capitalized costs	$	10,857,592	9,944,341

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

(b) Costs Incurred in Certain Oil and Gas Activities

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

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

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

(d) Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes the Company's royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the years ended December 31, 2017, 2018 and 2019 were prepared by the Company's reserve engineers and audited by DeGolyer and MacNaughton ("D&M") utilizing data compiled by the Company. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and timing of future development costs. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. All reserves are located in the United States.

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

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018 and 2019

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

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved reserves:				
December 31, 2016	9,414	957	38	15,386
Revisions	342	(22)	(6)	176
Extensions, discoveries and other additions	1,644	77	7	2,148
Production	(591)	(36)	(2)	(822)
Purchases of reserves	289	13	1	373
December 31, 2017	11,098	989	38	17,261
Revisions	(1,087)	8	(1)	(1,042)
Extensions, discoveries and other additions	2,125	98	12	2,781
Production	(711)	(43)	(3)	(989)
Purchases of reserves	—	—	—	—
December 31, 2018	11,425	1,052	46	18,011
Revisions	(1,735)	25	(11)	(1,648)
Extensions, discoveries and other additions	2,626	169	11	3,705
Production	(822)	(55)	(4)	(1,175)
Purchases of reserves	—	—	—	—
December 31, 2019	11,494	1,191	42	18,893

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

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

2017 Changes in Reserves

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

    - Net downward revisions of 188 Bcfe related to revisions to our five-year development plan. This figure includes upward revisions of 2,092 Bcfe for previously proved undeveloped properties reclassified from non-proved properties at December 31, 2016 to proved undeveloped at December 31, 2017 due to their addition to our five-year development plan, and downward revisions of 2,280 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
    - Upward revisions of 132 Bcfe were due to increases in prices for natural gas, NGLs, and oil.
    - Downward revisions of 113 Bcfe are due to a decrease in our assumed future ethane recovery.
- We produced 822 Bcfe during the year ended December 31, 2017.

2018 Changes in Reserves

- Extensions, discoveries, and other additions of 2,781 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales.
- Net downward revisions of 1,042 Bcfe include:
    - Downward revisions of 433 Bcfe related to well performance.
    - Net downward revisions of 742 Bcfe related to optimization to our five-year development plan. This figure includes upward revisions of 1,722 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to our five-year development plan, and downward revisions of 2,464 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
    - Upward revisions of 18 Bcfe were due to increases in prices for natural gas, NGLs, and oil.
    - Upward revisions of 115 Bcfe are due to an increase in our assumed future ethane recovery.

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

2019 Changes in Reserves

- Extensions, discoveries, and other additions of 3,705 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales.
- Net downward revisions of 1,648 Bcfe include:
    - Upward revisions of 63 Bcfe related to well performance.
    - Net downward revisions of 1,705 Bcfe related to optimization to our five-year development plan. This figure includes upward revisions of 595 Bcfe for previously proved undeveloped properties reclassified from non-proved properties due to their addition to our five-year development plan, and downward revisions of 2,300 Bcfe for locations that were not developed within five years of initial booking as proved reserves.
    - Downward revisions of 157 Bcfe were due to increases in prices for natural gas, NGLs, and oil.
    - Upward revisions of 315 Bcfe are due to an increase in our assumed future ethane recovery.
    - Downward revisions of 164 Bcfe are due to the deconsolidation of Antero Midstream Partners. Deconsolidation of Antero Midstream Partners resulted in Antero Resources recording the full fees paid to Antero Midstream Partners for services rendered and no longer including future capital expenditures associated with Antero Midstream Partners' assets in future development costs. Prior to deconsolidation, Antero Resources' consolidated reserves included the elimination of full fees paid by Antero Resources to Antero Midstream Partners and the inclusion of the operating costs and capital incurred by Antero Midstream Partners.

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

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

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

(in millions)	Year ended December 31, 2017	2018	2019
Future cash inflows	$ 55,824	64,199	54,228
Future production costs	(26,375)	(30,007)	(36,524)
Future development costs	(3,312)	(3,453)	(2,772)
Future net cash flows before income tax	26,137	30,739	14,932
Future income tax expense	(4,104)	(5,505)	(1,639)
Future net cash flows	22,033	25,234	13,293
10% annual discount for estimated timing of cash flows	(13,406)	(14,756)	(7,824)
Standardized measure of discounted future net cash flows	$ 8,627	10,478	5,469

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

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

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

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

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

Exhibit 4.5

ANTERO RESOURCES CORPORATION,

As Issuer and Parent Guarantor,

AR OHIO LLC

and

ANTERO WATER LLC,

as the New Guarantors,

and

WELLS FARGO BANK, NATIONAL ASSOCIATION,

as Trustee

THIRD SUPPLEMENTAL INDENTURE,

dated as of November 24, 2014

to Indenture

dated as of November 5, 2013

5.375% Senior Notes due 2021

This Third Supplemental Indenture, dated as of November 24, 2014 (this "Supplemental Indenture"), is among AR OHIO LLC and Antero Water LLC, Delaware limited liability companies (the "New Guarantors"), Antero Resources Corporation, a Delaware corporation (the "Issuer and Parent Guarantor," and together with the New Guarantors and Issuer and Parent Guarantor, the "Guarantors"), and Wells Fargo Bank, National Association, as Trustee under the Indenture referred to below.

W I T N E S S E T H:

WHEREAS, the Issuer and Parent Guarantor and the Trustee are parties to an indenture, dated as of November 5, 2013 (the "Base Indenture"), providing for the issuance of an aggregate principal amount of $1,000,000,000 of 5.375% Senior Notes due 2021 of the Issuer (the "Securities"), as supplemented by the First Supplemental Indenture, dated as of December 31, 2013, and the Second Supplemental Indenture, dated as of March 7, 2014 (the Base Indenture, as so supplemented, the "Indenture");

WHEREAS, there are no current Subsidiary Guarantors inasmuch as the two prior Subsidiary Guarantors, Antero Resources Midstream LLC and Antero Midstream LLC, have been re-designated as Unrestricted Subsidiaries pursuant to Section 1.1 of the Indenture, and as such have also been released from their Subsidiary Guarantees pursuant to Section 10.2(d) of the Indenture;

WHEREAS, Section 3.11 of the Base Indenture provides that after the Issue Date the Parent Guarantor is required to cause (a) each Wholly-Owned Subsidiary of the Parent Guarantor (other than a Foreign Subsidiary) formed or acquired after the Issue Date and (b) any other Domestic Subsidiary (except the Issuer and Parent Guarantor) that is not already a Subsidiary Guarantor that guarantees any Indebtedness of the Issuer and Parent Guarantor or a Subsidiary Guarantor, in each case to execute and deliver to the Trustee a supplemental indenture pursuant to which such Subsidiary will unconditionally guarantee, on a joint and several basis with the other Guarantors, the full and prompt payment of the principal of, premium, if any, and interest on the Securities;

WHEREAS, pursuant to Section 9.1 of the Base Indenture, the Trustee, the New Guarantors and the Issuer and Parent Guarantor are authorized to execute and deliver this Supplemental Indenture to amend or supplement the Indenture, without the consent of any Securityholder;

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the New Guarantors, the Issuer and Parent Guarantor and the Trustee mutually covenant and agree for the equal and ratable benefit of the Holders of the Securities as follows:

ARTICLE I
Definitions

SECTION 1.1 Defined Terms. As used in this Supplemental Indenture, terms defined in the Indenture or in the preamble or recitals hereto are used herein as therein defined. The words “herein,” “hereof” and “hereby” and other words of similar import used in this Supplemental Indenture refer to this Supplemental Indenture as a whole and not to any particular section hereof.

ARTICLE II
Agreement to Be Bound; Guarantee

SECTION 2.1 Agreement to Be Bound. Each of the New Guarantors hereby becomes a party to the Indenture as a Subsidiary Guarantor and as such will have all of the rights and be subject to all of the obligations and agreements of a Subsidiary Guarantor under the Indenture. Each of the New Guarantors agrees to be bound by all of the provisions of the Indenture applicable to a Subsidiary Guarantor and to perform all of the obligations and agreements of a Subsidiary Guarantor under the Indenture.

SECTION 2.2 Guarantee. Each of the New Guarantors agrees, on a joint and several basis, to fully, unconditionally and irrevocably Guarantee to each Holder of the Securities and the Trustee the Obligations pursuant to Article X of the Indenture.

ARTICLE III
Miscellaneous

SECTION 3.1 Notices. All notices and other communications to the New Guarantors shall be given as provided in the Indenture to the New Guarantors, at its address set forth below, with a copy to the Issuer as provided in the Base Indenture for notices to the Issuer.

AR OHIO LLC
1615 Wynkoop Street
Denver, Colorado 80202

Antero Water LLC
1615 Wynkoop Street
Denver, Colorado 80202

SECTION 3.2 Parties. Nothing expressed or mentioned herein is intended or shall be construed to give any Person, firm or corporation, other than the Holders and the Trustee, any legal or equitable right, remedy or claim under or in respect of this Supplemental Indenture or the Base Indenture or any provision herein or therein contained.

SECTION 3.3 Governing Law. This Supplemental Indenture shall be governed by, and construed in accordance with, the laws of the State of New York.

SECTION 3.4 Severability Clause. In case any provision in this Supplemental Indenture shall be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions shall not in any way be affected or impaired thereby and such provision shall be ineffective only to the extent of such invalidity, illegality or unenforceability.

SECTION 3.5 Ratification of Indenture; Supplemental Indenture Part of Indenture. Except as expressly supplemented and amended hereby, the Indenture is in all respects ratified and confirmed and all the terms, conditions and provisions thereof shall remain in full force and effect. This Supplemental Indenture shall form a part of the Indenture for all purposes, and every Holder of Securities heretofore or hereafter authenticated and delivered shall be bound hereby. The Trustee makes no representation or warranty as to the validity or sufficiency of this Supplemental Indenture or with respect to the recitals contained herein, all of which recitals are made solely by the other parties hereto.

SECTION 3.6 Counterparts. The parties hereto may sign one or more copies of this Supplemental Indenture in counterparts, all of which together shall constitute one and the same agreement. The exchange of copies of this Supplemental Indenture and of signature pages by facsimile or PDF transmission shall constitute effective execution and delivery of this Indenture as to the parties hereto. Signatures of the parties hereto transmitted by facsimile or PDF shall be deemed to be their original signatures for all purposes.

SECTION 3.7 Headings. The headings of the Articles and the Sections in this Supplemental Indenture are for convenience of reference only and shall not be deemed to alter or affect the meaning or interpretation of any provisions hereof.

(Signature Page Follows)

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed as of the date first above written.

ANTERO RESOURCES CORPORATION
AR OHIO LLC
ANTERO WATER LLC

By: /s/ Alvyn A. Schopp
Alvyn A. Schopp
Chief Administrative Officer and Regional Vice President

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Trustee

By: /s/ Patrick Giordano
Patrick Giordano
Vice President

Exhibit 4.6

ANTERO RESOURCES CORPORATION,

As Issuer and Parent Guarantor,

AR OHIO LLC and ANTERO WATER LLC,

as Subsidiary Guarantors,

MONROE PIPELINE LLC,

as the New Guarantor,

and

WELLS FARGO BANK, NATIONAL ASSOCIATION,

as Trustee

FOURTH SUPPLEMENTAL INDENTURE,

dated as of January 21, 2015

to Indenture

dated as of November 5, 2013

5.375% Senior Notes due 2021

This Fourth Supplemental Indenture, dated as of January 21, 2015 (this "Supplemental Indenture"), is among Monroe Pipeline LLC, a Delaware limited liability company (the "New Guarantor"), Antero Resources Corporation, a Delaware corporation (the "Issuer and Parent Guarantor," and together with the New Guarantor and Issuer and Parent Guarantor, the "Guarantors"), and Wells Fargo Bank, National Association, as Trustee under the Indenture referred to below.

W I T N E S S E T H:

WHEREAS, the Issuer and Parent Guarantor and the Trustee are parties to an indenture, dated as of November 5, 2013 (the "Base Indenture"), providing for the issuance of an aggregate principal amount of $1,000,000,000 of 5.375% Senior Notes due 2021 of the Issuer (the "Securities"), as supplemented by the First Supplemental Indenture, dated as of December 31, 2013, the Second Supplemental Indenture, dated as of March 7, 2014, and the Third Supplemental Indenture, dated as of November 24, 2014 (the Base Indenture, as so supplemented, the "Indenture");

WHEREAS, Section 3.11 of the Base Indenture provides that after the Issue Date the Parent Guarantor is required to cause (a) each Wholly-Owned Subsidiary of the Parent Guarantor (other than a Foreign Subsidiary) formed or acquired after the Issue Date and (b) any other Domestic Subsidiary (except the Issuer and Parent Guarantor) that is not already a Subsidiary Guarantor that guarantees any Indebtedness of the Issuer and Parent Guarantor or a Subsidiary Guarantor, in each case to execute and deliver to the Trustee a supplemental indenture pursuant to which such Subsidiary will unconditionally guarantee, on a joint and several basis with the other Guarantors, the full and prompt payment of the principal of, premium, if any, and interest on the Securities;

WHEREAS, pursuant to Section 9.1 of the Base Indenture, the Trustee, the New Guarantor and the Issuer and Parent Guarantor are authorized to execute and deliver this Supplemental Indenture to amend or supplement the Indenture, without the consent of any Securityholder;

NOW, THEREFORE, in consideration of the foregoing and for other good and valuable consideration, the receipt of which is hereby acknowledged, the New Guarantor, the Issuer and Parent Guarantor and the Trustee mutually covenant and agree for the equal and ratable benefit of the Holders of the Securities as follows:

ARTICLE I
Definitions

SECTION 1.1 Defined Terms. As used in this Supplemental Indenture, terms defined in the Indenture or in the preamble or recitals hereto are used herein as therein defined. The words "herein," "hereof" and "hereby" and other words of similar import used in this Supplemental Indenture refer to this Supplemental Indenture as a whole and not to any particular section hereof.

ARTICLE II
Agreement to Be Bound; Guarantee

SECTION 2.1 Agreement to Be Bound. The New Guarantor hereby becomes a party to the Indenture as a Subsidiary Guarantor and as such will have all of the rights and be subject to all of the obligations and agreements of a Subsidiary Guarantor under the Indenture. The New Guarantor agrees to be bound by all of the provisions of the Indenture applicable to a Subsidiary Guarantor and to perform all of the obligations and agreements of a Subsidiary Guarantor under the Indenture.

SECTION 2.2 Guarantee. The New Guarantor agrees, on a joint and several basis, to fully, unconditionally and irrevocably Guarantee to each Holder of the Securities and the Trustee the Obligations pursuant to Article X of the Indenture.

ARTICLE III
Miscellaneous

SECTION 3.1 Notices. All notices and other communications to the New Guarantor shall be given as provided in the Indenture to the New Guarantor, at its address set forth below, with a copy to the Issuer as provided in the Base Indenture for notices to the Issuer.

Monroe Pipeline LLC
1615 Wynkoop Street
Denver, Colorado 80202

SECTION 3.2 Parties. Nothing expressed or mentioned herein is intended or shall be construed to give any Person, firm or corporation, other than the Holders and the Trustee, any legal or equitable right, remedy or claim under or in respect of this Supplemental Indenture or the Base Indenture or any provision herein or therein contained.

SECTION 3.3 Governing Law. This Supplemental Indenture shall be governed by, and construed in accordance with, the laws of the State of New York.

SECTION 3.4 Severability Clause. In case any provision in this Supplemental Indenture shall be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions shall not in any way be affected or impaired thereby and such provision shall be ineffective only to the extent of such invalidity, illegality or unenforceability.

SECTION 3.5 Ratification of Indenture; Supplemental Indenture Part of Indenture. Except as expressly supplemented and amended hereby, the Indenture is in all respects ratified and confirmed and all the terms, conditions and provisions thereof shall remain in full force and effect. This Supplemental Indenture shall form a part of the Indenture for all purposes, and every Holder of Securities heretofore or hereafter authenticated and delivered shall be bound hereby. The Trustee makes no representation or warranty as to the validity or sufficiency of this Supplemental Indenture or with respect to the recitals contained herein, all of which recitals are made solely by the other parties hereto.

SECTION 3.6 Counterparts. The parties hereto may sign one or more copies of this Supplemental Indenture in counterparts, all of which together shall constitute one and the same agreement. The exchange of copies of this Supplemental Indenture and of signature pages by facsimile or PDF transmission shall constitute effective execution and delivery of this Indenture as to the parties hereto. Signatures of the parties hereto transmitted by facsimile or PDF shall be deemed to be their original signatures for all purposes.

SECTION 3.7 Headings. The headings of the Articles and the Sections in this Supplemental Indenture are for convenience of reference only and shall not be deemed to alter or affect the meaning or interpretation of any provisions hereof.

(Signature Page Follows)

IN WITNESS WHEREOF, the parties hereto have caused this Supplemental Indenture to be duly executed as of the date first above written.

ANTERO RESOURCES CORPORATION
AR OHIO LLC
ANTERO WATER LLC
MONROE PIPELINE LLC

By: /s/ Alvyn A. Schopp
Alvyn A. Schopp
Chief Administrative Officer and Regional Vice President

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Trustee

By: /s/ John Stohlmann
John Stohlmann
Vice President

Signature Page to Supplemental Indenture

Exhibit 4.20

DESCRIPTION OF COMMON STOCK

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

Common Stock

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

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

Anti-Takeover Provisions of Our Certificate of Incorporation and Bylaws

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

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

Delaware Law

Section 203 of the DGCL prohibits a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

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

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

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

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

Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws

Among other things, our Certificate of Incorporation and Bylaws:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year (unless the date of the annual meeting is more than 30 days before or more than 60 days after such anniversary date, in which case such notice must be delivered no earlier than the close of business on the 120th day prior to such annual meeting or later than the close of business on the later of the 90th day prior to such annual meeting or, if the first public announcement of the date of such annual meeting is less than 100 days prior to the date of such annual meeting, the 10th day after the first public disclosure of the date of such meeting by us). Our Bylaws specify the requirements as to form and content of all stockholders" notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;

- provide that the authorized number of directors may be changed only by resolution of the board of directors;

- provide that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

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

- provide our Certificate of Incorporation and Bylaws may be amended by the affirmative vote of the holders of at least two thirds of our then outstanding common stock;

- provide that special meetings of our stockholders may only be called by the board of directors, the chief executive officer or the chairman of the board;

- provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any. This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;

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

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

Exhibit 10.4

Execution Version

SECOND AMENDED AND RESTATED GATHERING AND COMPRESSION AGREEMENT
BY AND BETWEEN

ANTERO RESOURCES CORPORATION

AND

ANTERO MIDSTREAM LLC

DATED AS OF

DECEMBER 8, 2019

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SECOND AMENDED AND RESTATED GATHERING AND COMPRESSION AGREEMENT

This Second Amended and Restated Gathering and Compression Agreement (this "***Agreement***"), dated as of December 8, 2019 (the "***Effective Date***"), is by and between **ANTERO RESOURCES CORPORATION**, a Delaware corporation ("***Shipper***"), and **ANTERO MIDSTREAM LLC**, a Delaware limited liability company ("***Gatherer***"). Shipper and Gatherer may be referred to herein individually as a "***Party***" or collectively as the "***Parties***."

RECITALS

A. Shipper owns Oil and Gas Interests and intends to produce Gas and/or Liquid Hydrocarbons from Wells in the Initial Dedication Area and may from time to time own Oil and Gas Interests and may produce Gas and Liquid Hydrocarbons from Wells in other areas.

B. Gatherer has acquired the Gathering System, which gathers Gas and Liquid Hydrocarbons from certain Wells of Shipper, from Shipper. Gatherer anticipates the expansion of the Gathering System to connect additional Wells of Shipper.

C. Shipper desires to contract with Gatherer to provide the Services on the Gathering System with respect to Dedicated Production, including compressing Dedicated Gas at the System Compression Stations, and Gatherer desires to provide the Services to Shipper, in each case in accordance with the terms and conditions of this Agreement.

D. Shipper and Gatherer initially were parties to that certain Gas Gathering and Compression Agreement (the "***Original Agreement***"), dated as of November 10, 2014 (the "***Original Agreement Effective Date***").

E. Shipper and Gatherer amended and restated the Original Agreement in its entirety pursuant to that certain First Amended and Restated Gathering and Compression Agreement dated as of February 13, 2018 (the "***First A&R Agreement***").

F. The Parties desire to amend and restate the First A&R Agreement in its entirety on the terms set forth herein.

NOW THEREFORE, in consideration of the premises and mutual covenants set forth in this Agreement, the Parties agree as follows:

ARTICLE 1
DEFINITIONS

Capitalized terms used, but not otherwise defined, in this Agreement shall have the respective meanings given to such terms set forth below:

Adequate Assurance of Performance. As defined in Section 13.6(a).

Affiliate. Any Person that, directly or indirectly through one or more intermediaries, controls or is controlled by or is under common control with another Person. ***Affiliated*** shall have the correlative meaning. The term "control" (including its derivatives and similar terms) shall mean possessing the power to direct or cause the direction of the management and policies of a Person, whether through ownership, by contract, or otherwise. Notwithstanding the foregoing, any Person shall be deemed to control any specified Person if such Person owns fifty percent (50%) or more of the voting securities of the specified Person, or if the specified Person owns fifty percent (50%) or more of the voting securities of such Person, or if fifty percent (50%) or more of the voting securities of the specified Person and such Person are under common control. Notwithstanding the foregoing, for purposes of this Agreement, none of Antero Midstream Corporation or any of its direct or indirect subsidiaries (including Gatherer) shall be an Affiliate of Shipper, and neither Shipper nor any of its direct or indirect subsidiaries (other than Antero Midstream Corporation and its direct and indirect subsidiaries) shall be an Affiliate of Gatherer.

Agreement. As defined in the preamble hereof.

Average Quarterly Receipt Point Volumes . For each calendar quarter beginning on January 1, 2020 and ending December 31, 2023, (a) the aggregate of the volumes of Dedicated Production, stated in MMcf, delivered at each Receipt Point during such calendar quarter *divided by* (b) the number of Days in such calendar quarter.

Barrel. Forty-two Gallons.

Btu. The amount of heat required to raise the temperature of one pound of pure water from 58.5 degrees Fahrenheit to 59.5 degrees Fahrenheit at a constant pressure of 14.73 psia.

Business Day. Any calendar Day that commercial banks in New York City are open for business.

Completion Deadline. As defined in Section 3.3(c).

Compression Fee. As defined in Section 5.1(a)(iii).

Condensate. Gas that condenses at the wellhead or in the Gathering System at ambient temperatures and is recovered from the Gathering System or at the wellhead as a hydrocarbon liquid.

Confidential Information. As defined in Section 18.6(a).

Conflicting Dedication. Any gathering agreement or other commitment or arrangement that would require Dedicated Production to be gathered and/or compressed on any gathering system other than the Gathering System.

Connection Notice. As defined in Section 3.3(c).

Contract Year . Each of (i) the period from the Original Agreement Effective Date to the last Day of the Month in which the first anniversary of the Original Agreement Effective Date occurs and (ii) each period of twelve (12) Months thereafter.

Cost of Service Fee. As defined in Section 5.1(e).

CPI. As defined in Section 5.1(b).

CS Facility. As defined in Section 5.1(e).

Cubic Foot. The volume of Gas in one cubic foot of space at a standard pressure and temperature base of 14.73 psia and 60 degrees Fahrenheit, respectively.

Day. A period commencing at 10:00 a.m., Eastern Standard Time, on a calendar day and ending at 10:00 a.m., Eastern Standard Time, on the next succeeding calendar day. ***Daily*** shall have the correlative meaning.

Dedicated Gas. Gas constituting Dedicated Production.

Dedicated Production. All Production that is attributable to any Dedicated Property (including all Production attributable to third parties that is produced from a Well located on such Dedicated Property) that Shipper has the right to control and deliver for gathering and that is produced on or after the Dedication Effective Date with respect to such Dedicated Property, except for Gas being produced from the wells identified in Exhibit A.

Dedicated Properties. All Oil and Gas Interests now owned or hereafter acquired by Shipper and located wholly or partly within the Dedication Area or pooled, unitized or communitized with Oil and Gas Interests located wholly or partly within the Dedication Area; provided that Dedicated Properties shall not include any Oil and Gas Interests that are unitized or pooled with the properties of third parties that are not Dedicated Properties if Shipper is not the operator of such unit.

Dedication Area. The Initial Dedication Area and any other area that becomes part of the Dedication Area pursuant to Section 2.5.

Dedication Effective Date. With respect to Dedicated Properties owned by Shipper as of the Original Agreement Effective Date, the Original Agreement Effective Date; and with respect to Dedicated Properties acquired by Shipper after the Original Agreement Effective Date, the date such Oil and Gas Interests became or become Dedicated Properties pursuant to Section 2.5.

Delay Notice. As defined in Section 3.3(f).

Delayed Well Pad. As defined in Section 3.3(f).

Delivery Point. Each point at which point Gatherer will redeliver Production to Shipper or for its account, which shall be (i) in the case of Gas, the point of interconnection of the Gathering System with the facilities of a Processing Plant or Downstream Pipeline, including those points more particularly described on Exhibit B, (ii) in the case of Liquid Hydrocarbons recovered at the wellhead, the inlet flange of the storage tank at the facilities nominated by Shipper into which such Liquid Hydrocarbons are delivered from the Gathering System or from the truck, including those points more particularly described on Exhibit B, and (iii) in the case of Condensate that is recovered from Gas gathering facilities at a System Compressor Station, the outlet flange of the storage tank at such System Compressor Station into which such Condensate is delivered.

Delivery Point Gas. A quantity of Gas having a Thermal Content equal to the total Thermal Content of the Dedicated Gas received by Gatherer from Shipper at the Receipt Points, less (i) the Thermal Content of Gas used for Fuel, (ii) the Thermal Content of Condensate recovered from the Gathering System, and (iii) the Thermal Content of Lost and Unaccounted for Gas, in each case, as allocated to Shipper in accordance with this Agreement.

Development Plan. As defined in Section 3.2(a).

Downstream Pipeline. Any Gas pipeline or any facilities of any end-user or local distribution company, in each case downstream of the Gathering System, into which Shipper's Gas is delivered from the Gathering System or a Processing Plant.

Effective Date. As defined in the preamble of this Agreement.

Emissions Charges. As defined in Section 10.5.

Fair Market Value. With respect to any asset, the price that would be paid by a willing buyer of such asset to a willing seller, as determined by an independent nationally known investment banking firm selected by Gatherer and reasonably acceptable to Shipper.

Fee Rebate. As defined in Section 5.2(a).

FERC. As defined in Section 18.2.

Firm Capacity Production. Production that is accorded the highest priority on the Gathering System with respect to capacity allocations, interruptions, or curtailments, specifically including (i) Dedicated Production and (ii) Production delivered to the Gathering System from any Person for which Gatherer is contractually obligated to provide the highest priority. Firm Capacity Production will be the last Production removed from the relevant part of the Gathering System in the event of an interruption or curtailment and all Firm Capacity Production, including Dedicated Production, will be treated equally in the event an allocation is necessary.

First A&R Agreement. As defined in the recitals of this Agreement.

Force Majeure. As defined in Section 14.2.

Fuel. Gas and electric power used in the operation of the Gathering System, including fuel consumed in System Compressor Stations and dehydration facilities that are part of the Gathering System.

Gallon. One U.S. gallon, which is equal to 231 cubic inches.

Gas. Any mixture of gaseous hydrocarbons, consisting essentially of methane and heavier hydrocarbons and inert and noncombustible gases, that is extracted from beneath the surface of the earth.

Gas Quality Specifications. As defined in Section 10.1.

Gatherer. As defined in the preamble of this Agreement.

Gathering Fee. As defined in Section 5.1(a)(i).

Gathering System. The gathering system described in Exhibit C acquired by Gatherer from Shipper as of the Original Agreement Effective Date, together with any additional System Segments constructed after the Original Agreement Effective Date, as such gathering system is expanded after the Original Agreement Effective Date, including, in each case, to the extent now in existence or constructed or installed in the future, Low Pressure Gas gathering pipelines, Liquid Hydrocarbons gathering pipelines, High Pressure Gas gathering pipelines, System Compressor Stations, Gas dehydration facilities, Receipt Points, Delivery Points (including all interconnection facilities), Measurement Facilities, Condensate handling facilities, pig receiving facilities, slug catchers and other inlet facilities at Processing Plants, rights of way, fee parcels, surface rights, and permits, and all appurtenant facilities, in each cased owned by Gatherer and its Affiliates.

Gathering System Plan. As defined in Section 3.2(b).

Gross Heating Value. The number of Btus produced by the complete combustion in air, at a constant pressure, of one Cubic Foot of Gas when the products of combustion are cooled to the initial temperature of the Gas and air and all water formed by combustion is condensed to the liquid state.

Governmental Authority. Any federal, state, local, municipal, tribal or other government; any governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, regulatory or taxing authority or power; and any court or governmental tribunal, including any tribal authority having or asserting jurisdiction.

High Pressure. Pipelines gathering or transporting Gas that has been dehydrated and compressed to the pressure of the Downstream Pipelines or Processing Plants at the Delivery Points.

High Pressure Gathering Fee. As defined in Section 5.1(a)(ii).

Ideal Gas Laws. The thermodynamic laws applying to perfect gases.

Imbalance. As defined in Section 9.3.

Incurred Costs. As defined in Section 3.3(f).

Index Price. For Gas produced from the Marcellus formation in West Virginia, the "Midpoint Average" price published in Platt's Gas Daily Price Guide for "Columbia Gas/Appalachia". For Gas produced from the Utica formation in Ohio, the "Midpoint Average" price published in Platt's Gas Daily Price Guide for "Texas Eastern M-2 Receipts". For other Gas production, an index price determined by Shipper and reasonably acceptable to Gatherer based on where such Gas production is being sold, or, if no appropriate index is available, a price based on a netback calculation determined by Shipper and reasonably acceptable to Gatherer.

Initial Dedication Area. For Gas, the states of Pennsylvania, West Virginia, and Ohio; for Liquid Hydrocarbons, the states of West Virginia and Ohio.

Initial Development Plan. The Development Plan attached hereto as Exhibit D.

Interruptible Production. Production that is accorded the lowest priority on the Gathering System with respect to capacity allocations, interruptions, or curtailments. Interruptible Production will be the first Production removed from the Gathering System in the event of an interruption or curtailment.

Liquids Gathering Fee. As defined in Section 5.1(a)(iv).

Liquid Hydrocarbons. Oil, Condensate, natural gasoline and all the liquid hydrocarbon production from wells, or a blend of such, in its natural form, not having been processed, other than for removal of water at the wellhead.

Lost and Unaccounted For Gas. Gas received into the Gathering System that is released or lost through piping, equipment, operations, or measurement losses or inaccuracies or that is vented, flared or lost in connection with the operation of the Gathering System.

Low Pressure. Pipelines gathering Gas at or near wellhead pressure that has yet to be compressed (other than by well pad gas lift compression or dedicated well pad compressors) and dehydrated.

Made Available for Delivery. In connection with deliveries of Dedicated Production under this Agreement, Dedicated Production that is unable to be delivered to the applicable point as a result of Gatherer's failure to perform its obligations under this Agreement.

Maintenance. As defined in Section 7.2.

Mcf. One thousand (1,000) Cubic Feet.

Measurement Facilities. Any facility or equipment used to measure the volume of Gas or Liquid Hydrocarbons, which may include meter tubes, LACT units, isolation valves, tank strappings, recording devices, communication equipment, buildings and barriers.

Minimum Compression Volume Commitment. With respect to any Contract Year from the Contract Year in which the first System Compressor Station is placed in service through the earlier of the Contract Year in which occurs the tenth (10th) anniversary of the placement in service of the last System Compressor Station to be placed in service or the expiration or termination of the term of this Agreement, a volume of Dedicated Gas, stated in Mcf, equal to the sum of all such volumes calculated at each System Compressor Station that has been in service for ten (10) years or less, each of which shall be calculated as follows: the product of (i) the total design capacity, stated in Mcf per Day, of the relevant System Compressor Station, multiplied by (ii) subject to the immediately following sentence, the number of Days in such

Contract Year, multiplied by (iii) 0.70. For purposes of the foregoing calculation the design capacity of a particular System Compressor Station shall be included (1) only to the extent that such capacity has been installed at the direction of the Shipper in accordance with Section 3.4(a) and does not represent additional capacity installed at such System Compressor Station by Gatherer as permitted by Section 3.4(a), (2) for not more than the 10 year period after it is first placed in service, (3) in the Contract Year in which it is placed in service, only for the number of Days in such Contract Year after it has been placed in service, and (4) if arising prior to the expiration or termination of the term of this Agreement, in the Contract Year in which the 10th anniversary of its placement in service occurs, only for the number of Days through such 10th anniversary.

Minimum High Pressure Volume Commitment . With respect to any Contract Year from the Contract Year in which the first System High Pressure Line is placed in service through the earlier of the Contract Year in which occurs the tenth (10th) anniversary of the placement in service of the last System High Pressure Line to be placed in service or the expiration or termination of the term of this Agreement, a volume of Dedicated Gas, stated in Mcf, equal to the sum of all such volumes calculated at each System High Pressure Line that has been in service for ten (10) years or less, each of which shall be calculated as follows: the product of (i) the total design capacity, stated in Mcf per Day, of the relevant System High Pressure Line, as reasonably calculated by Gatherer based on the capacity of the relevant System Compressor Station and the length and diameter of such System High Pressure Line, multiplied by (ii) subject to the immediately following sentence, the number of Days in such Contract Year, multiplied by (iii) 0.75. For purposes of the foregoing calculation the design capacity of a particular System High Pressure Line shall be included (1) for not more than the 10 year period after it is first placed in service, (2) in the Contract Year in which it is placed in service, only for the number of Days in such Contract Year after it has been placed in service, and (3) if arising prior to the expiration or termination of the term of this Agreement, in the Contract Year in which the 10th anniversary of its placement in service occurs, only for the number of Days through such 10th anniversary.

MMBtu. One million (1,000,000) Btus.

MMcf. One million (1,000,000) Cubic Feet.

Monitoring Services Provider. As defined in Section 11.10(a).

Month. A period commencing at 10:00 a.m., Eastern Standard Time, on the first Day of a calendar month and extending until 10:00 a.m., Eastern Standard Time, on the first Day of the next succeeding calendar month. ***Monthly*** shall have the correlative meaning.

Oil and Gas Interests. Oil and gas leasehold interests and oil and gas mineral fee interests, including working interests, overriding royalty interests, net profits interests, carried interests, and similar rights and interests.

Original Agreement. As defined in the recitals of this Agreement.

Original Agreement Effective Date. As defined in the recitals of this Agreement.

Original Connection Notice. As defined in Section 3.3(f).

Parties. As defined in the preamble of this Agreement.

Party. As defined in the preamble of this Agreement.

Person. An individual, a corporation, a partnership, a limited partnership, a limited liability company, an association, a joint venture, a trust, an unincorporated organization, or any other entity or organization, including a Governmental Authority.

Planned Well. As defined in Section 3.2(a).

Planned Well Pad. As defined in Section 3.2(a).

Production. Gas and/or Liquid Hydrocarbons.

Processing Plant. Any Gas processing facility downstream of any portion of the Gathering System to which Shipper has dedicated Gas for processing or at which Shipper has arranged for Gas to be processed prior to delivery to a Downstream Pipeline.

psia. Pounds per square inch, absolute.

psig. Pounds per square inch, gauge.

Receipt Point. The inlet valve at the Measurement Facilities owned by Gatherer located at or nearby or assigned to a Well Pad where one or more Wells are connected to the Gathering System or, in the case of Liquid Hydrocarbons, the outlet of the pump connected to one or more of Shipper's tanks receiving Liquid Hydrocarbons from such Wells.

Remote Monitoring Data. As defined in Section 11.10(a).

Required Compressor Station. As defined in Section 3.4(a).

Required High Pressure Lines. As defined in Section 3.5.

Services. As defined in Section 3.1.

Shipper. As defined in the preamble of this Agreement.

Shipper's GHG Emissions. As defined in Section 10.5.

Six Month Deadline. As defined in Section 3.3(f)(ii).

System Compressor Station. As defined in Section 3.4(a).

System Delivery Point. Each point at which Gatherer redelivers Production from the Gathering System to or for the account of shippers, including the Delivery Points.

System High Pressure Line. As defined in Section 3.5.

System Receipt Point. Each point where Production first enters the Gathering System, including the Receipt Points.

System Segment. A physically separate segment of the Gathering System that connects one or more of Shipper's Wells to one or more Delivery Points, including all Low Pressure Gas gathering pipelines, Liquid Hydrocarbons gathering pipelines, High Pressure Gas gathering pipelines, System Compressor Stations, Gas dehydration facilities, Receipt Points, Delivery Points, Measurement Facilities owned by Gatherer, Condensate handling facilities, rights of way, fee parcels, surface rights, and permits, and all appurtenant facilities.

Target Completion Date. As defined in Section 3.3(c).

Taxes. All gross production, severance, conservation, ad valorem and similar or other taxes measured by or based upon production, together with all taxes on the right or privilege of ownership of Production, or upon the Services, including gathering, transportation, handling, transmission, compression, processing, treating, conditioning, distribution, sale, use, receipt, delivery or redelivery of Production, including, without limitation, gross receipts taxes, and including all of the foregoing now existing or in the future imposed or promulgated.

Thermal Content. For Gas, the product of (i) a volume of Gas in Cubic Feet and (ii) the Gross Heating Value of such Gas, as expressed in MMBtus. For Condensate, the product of the measured volume in Gallons multiplied by the Gross Heating Value per Gallon determined in accordance with the GPA 2145-09 Table of Physical Properties for Hydrocarbons and GPA 8173 Method for Converting Mass of Natural Gas Liquids and Vapors to Equivalent Liquid Volumes, in each case as revised from time to time; provided, however, that if sufficient data has not been obtained to make such calculation, the Thermal Content of Condensate shall be deemed to be 0.115 MMBtu per Gallon.

Third Party Production. Production produced by Persons other than Shipper and not considered Dedicated Production hereunder.

Well. A well for the production of hydrocarbons in which Shipper owns an interest that produces or is intended to produce Dedicated Production or otherwise is connected or is required to be connected to the Gathering System in accordance with this Agreement.

Well Pad. The surface installation on which one or more Wells are located.

ARTICLE 2
SHIPPER COMMITMENTS

Section 2.1 Shipper's Dedication. Subject to Section 2.2 through Section 2.4, (a) Shipper exclusively dedicates and commits to deliver to Gatherer, as and when produced, all Dedicated Production for gathering through the Gathering System under this Agreement, including (in the case of Dedicated Gas) High Pressure gathering and compression in the System Compressor Stations, and (b) Shipper agrees not to deliver any Dedicated Production to any other gathering system or compressor station.

Section 2.2 Conflicting Dedications. Shipper shall have the right to comply with each of the Conflicting Dedications set forth in Exhibit E hereto and any other Conflicting Dedication entered into by a non-Affiliated predecessor-in-interest to Shipper to which any Dedicated Property acquired by Shipper after the Original Agreement Effective Date is subject as of the date of acquisition thereof (other than any Conflicting Dedication entered into by such predecessor-in-interest at the direction of Shipper or any of its Affiliates in connection with such acquisition, but subject to the remainder of this Section 2.2), whether such Conflicting Dedication is documented in an agreement binding upon such predecessor-in-interest that is assigned to and/or assumed by Shipper (fully or partially) and/or in a new agreement binding upon Shipper that replaces (fully or partially) the agreement binding upon such predecessor-in-interest, as long as neither the scope nor term of the Conflicting Dedication are extended beyond that applicable to such predecessor-in-interest at the time of the acquisition; provided, however, that Shipper shall have the right to comply with Conflicting Dedications only until the first Day of the Month following the termination of such Conflicting Dedication and shall not take any voluntary action (including the exercise of any right to extend) to extend the term of such Conflicting Dedication beyond the minimum term provided for in the document evidencing such Conflicting Dedication. Shipper represents that, except as set forth in Exhibit E, Dedicated Production was not as of the Original Agreement Effective Date subject to any Conflicting Dedication. If Dedicated Production produced from a Well on a Well Pad is subject to a Conflicting Dedication that Shipper has the right to comply with under this Section 2.2, Shipper has the right, in complying with such Conflicting Dedication, to deliver all Dedicated Production from such Well Pad in accordance with the Conflicting Dedication, even if all Wells on such Well Pad are not subject to such Conflicting Dedication.

Section 2.3 Shipper's Reservations. Shipper reserves the following rights with respect to Dedicated Production for itself and for the operator of the relevant Dedicated Properties: (a) to operate Wells producing Dedicated Production as a reasonably prudent operator in its sole discretion, including the right, but never the obligation, to drill new Wells, to repair and rework old Wells, to renew or extend, in whole or in part, any Oil and Gas Interest covering any of the Dedicated Properties, and to cease production from or abandon any Well or surrender any such Oil and Gas Interest, in whole or in part, when no longer deemed by Shipper to be capable of producing Production in paying quantities under normal methods of operation; (b) to use Dedicated Production for operations (including reservoir pressure maintenance and drilling or fractionation fuel); (c) to deliver or furnish to Shipper's lessors and holders of other existing similar burdens on production such Production as is required to satisfy the terms of the applicable leases or other applicable instruments; (d) to acquire Wells connected to existing gathering systems and to continue to deliver to such gathering systems Production produced from such Wells, provided that, to the extent that Production from such Wells constitutes Dedicated Production, Shipper delivers a Connection Notice to Gatherer with respect to any such Well not later than 30 Days after its acquisition and thereafter delivers Production to such gathering system only until Gatherer has connected such Well to the Gathering System in accordance with Section 3.3; (e) to pool, communitize, or unitize Shipper's Oil and Gas Interests with respect to Dedicated Production, provided that the share of Production produced from such pooled, communitized, or unitized Oil and Gas Interests shall be committed and dedicated to this Agreement; and (f) to gather Liquid Hydrocarbons produced from the Marcellus formation in trucks.

Section 2.4 Covenant Running with the Land. The dedication and commitment made by Shipper under this Article 2 is a covenant running with the land. For the avoidance of doubt and in addition to that which is provided in Section 18.4, in the event Shipper sells, transfers, conveys, assigns, grants, or otherwise disposes of any or all of its interest in the Dedicated Properties, then any such sale, transfer, conveyance, assignment, grant, or other disposition shall be expressly subject to this Agreement and any instrument of conveyance shall so state. Notwithstanding the foregoing, Shipper shall be permitted to sell, transfer, convey, assign, grant, or otherwise dispose of Dedicated Properties free of the dedication hereunder (i) in a sale or other disposition in which a number of net acres of Dedicated Properties that, when added to the total of net acres of Dedicated Properties theretofore and, where applicable, simultaneously disposed of free of dedication hereunder pursuant to this Section 2.4, does not exceed the aggregate number of net acres of Dedicated Properties acquired by Shipper after the Original Agreement Effective Date, including in a transaction in which Dedicated Properties are exchanged for other properties located in the Dedication Area that would be subject to dedication hereunder or (ii) in a sale of Wells located on Dedicated Properties that are pooled or unitized with the properties of third parties that are not Dedicated Properties if Shipper is not the operator of such unit; provided, however, that any such sale, transfer, conveyance, assignment, grant or other disposition of Dedicated Properties shall not include, and there shall be expressly excluded therefrom, any Well that is or has been connected to the Gathering System (whether producing, shut-in, temporarily abandoned or which has been spud or as to which drilling, completion, reworking or other well operations have commenced) or which is located on a Well Pad for which a Connection Notice has previously been delivered by Shipper (unless the completion of such Well has been delayed and Shipper has paid the costs and expenses incurred by Gatherer in connection therewith in accordance with Section 3.3(d)). At the request of Gatherer, the Parties shall execute and record an amendment to the memorandum of this Agreement previously entered into, as provided in Section 18.16, to reflect additions to the Dedicated Properties.

Section 2.5 Additional Oil and Gas Interests or Gathering Facilities.

(a) If Shipper acquires any existing gathering facilities gathering Production from any Oil and Gas Interests, it shall, by notice to Gatherer on or before the 10th Day after such acquisition, which notice shall include a reasonable description of such gathering facilities and such Oil and Gas Interests (including an update to the Development Plan reflecting such Oil and Gas Interests) and the price paid by Shipper for such gathering facilities, including any liabilities assumed by Shipper, offer to sell to Gatherer such gathering facilities, including all Low Pressure Gas gathering pipelines, High Pressure Gas gathering pipelines, Liquid Hydrocarbons gathering pipelines, compressor stations, Gas dehydration facilities, receipt points, delivery points, measurement facilities, Condensate handling facilities, rights of way, fee parcels, surface rights, and permits, and all appurtenant facilities, as well as any third party shipper contracts for Production gathered on such gathering facilities, at the same price at which such gathering facilities were acquired by Shipper, including the assumption of any liabilities with respect thereto assumed by Shipper. Gatherer shall have the right, to be exercised by notice to Shipper on or before the 60th Day after Shipper's notice of its acquisition of such gathering facilities, to acquire such gathering facilities at such price (including the assumption of such liabilities). If Gatherer does not give such notice to Shipper on or before such 60th Day, Gatherer shall be deemed to have waived its right to acquire such gathering facilities, except in the case of a third party gathering offer as provided below, and (i)

Shipper shall have the right to own and operate such facilities to gather the Production from the Oil and Gas Interests described in such notice and/or (ii) Shipper shall have the right to solicit proposals from a third party gatherer to acquire, own, and operate such facilities to gather the Production from the Oil and Gas Interests described in such notice on the basis that Shipper will dedicate to such gatherer all Oil and Gas Interests owned by Shipper the Production from which is being gathered by such gathering facilities as well as the area (including all geological strata and production zones) within two miles of any such Oil and Gas Interest. If Shipper obtains any such third party proposal, it shall, by notice to Gatherer, provide Gatherer with all the terms and conditions thereof, and Gatherer shall have the right to elect, by notice to Shipper on or before the 60th Day after its receipt of Shipper's notice containing the terms and conditions of such proposal, to acquire such gathering facilities and provide such services on the same terms and conditions as those offered by the third party gatherer. If Gatherer does not so elect on or before such 60th Day, Gatherer shall be deemed to have waived its right to acquire such gathering facilities and provide such services, and Shipper shall have the right to contract with such third party gatherer to acquire such facilities and to provide such services on such terms and conditions and to dedicate to such gatherer all Oil and Gas Interests owned by Shipper the Production from which is being gathered by such gathering facilities as well as the area (including all geological strata and production zones) within two miles of any such Oil and Gas Interest. If Gatherer elects to acquire such gathering facilities, the closing of Gatherer's purchase of such gathering facilities from Shipper shall take place as soon as reasonably practicable following Gatherer's exercise of its right to acquire such gathering facilities. From and after the closing of such purchase by Gatherer, all Oil and Gas Interests owned by Shipper the Production from which is being gathered by such gathering facilities shall be Dedicated Properties, the area (including all geological strata and production zones) within two miles of any such Dedicated Property shall become part of the Dedication Area, and such gathering facilities shall be deemed to be part of the Gathering System. In any transaction in which Shipper so acquires gathering facilities, Shipper shall use reasonable efforts to cause the transaction documents for such acquisition to state a separate purchase price (and separately state any assumed liabilities) for such gathering facilities. If notwithstanding such reasonable efforts the transaction documents for such acquisition do not state a separate purchase price, the purchase price to be paid by Gatherer to Shipper for such gathering facilities shall be equal to the Fair Market Value of such gathering facilities, and Gatherer shall assume all liabilities in respect of such gathering facilities to the extent arising from the ownership and operation of such gathering facilities and/or any occurrence from and after the closing of the purchase of such gathering facilities by Gatherer.

(b) If at any time Shipper desires to construct, own, and operate, or to have constructed and operated, gathering facilities to gather Production from Oil and Gas Interests located outside the then-existing Dedication Area, Shipper shall, by notice to Gatherer specifying (i) the facilities it desires and the receipt points and delivery points it plans to connect, (ii) the Oil and Gas Interests acquired by Shipper the Production from which will be gathered using such facilities, and (iii) a proposed update to the Development Plan reflecting the Wells to be drilled on such Oil and Gas Interests during the period of at least 18 Months after such notice, including production forecasts for all such Wells, offer to Gatherer the opportunity to construct, own, and operate such facilities as part of the Gathering System on the terms set forth in this Agreement. Gatherer shall have the right, to be exercised by notice to Shipper on or before the 60th Day after Shipper's notice, to elect to construct, own, and operate such facilities. If Gatherer exercises such right, from and after the date of Gatherer's notice of exercise, all Oil and Gas Interests owned by Shipper described in Gatherer's notice shall be Dedicated Properties, the area (including all geological strata and production zones) within two miles of any such Dedicated Property shall become part of the Dedication Area, such gathering facilities as they are constructed shall be deemed to be part of the Gathering System, and the proposed development plan included in Shipper's notice shall become part of the Development Plan. If Gatherer does not give such notice to Shipper on or before such 60th Day, Gatherer shall be deemed to have waived its right to construct, own, and operate the facilities set forth in Shipper's notice as part of the Gathering System on the terms set forth in this Agreement, except in the case of a third party gathering offer as provided below, and (1) Shipper shall have the right to construct, own, and operate such facilities to gather the Production from the Oil and Gas Interests described in such notice or (2) Shipper shall have the right to solicit proposals from a third party gatherer to construct, own, and operate such facilities to gather the Production from the Oil and Gas Interests described in such notice on the basis that Shipper will dedicate to such gatherer all Oil and Gas Interests described in such notice as well as the area (including all geological strata and production zones) within two miles of any such Oil and Gas Interest. If Shipper obtains any such third party proposal, it shall, by notice to Gatherer, provide Gatherer with all the terms and conditions thereof, and Gatherer shall have the right to elect, by notice to Shipper on or before the 60th Day after its receipt of Shipper's notice containing the terms and conditions of such proposal, to construct, own, and operate such facilities to gather the Production from the Oil and Gas Interests described in such notice on the same terms and conditions as those offered by the third party gatherer. If Gatherer does not so elect on or before such 60th Day, Gatherer shall be deemed to have waived its right to provide such services, and Shipper shall have the right to contract with such third party gatherer to provide such services on such terms and conditions and to dedicate to such gatherer the Oil and Gas Interests described in such notice as well as the area (including all geological strata and production zones) within two miles of any such Oil and Gas Interest.

Section 2.6 Priority of Dedicated Production. Dedicated Production tendered under this Agreement shall be Firm Capacity Production.

ARTICLE 3
SERVICES; GATHERING SYSTEM EXPANSION AND CONNECTION OF WELLS

Section 3.1 Gatherer Service Commitment. Subject to and in accordance with the terms and conditions of this Agreement, Gatherer commits to providing the following services (collectively, the "***Services***") to Shipper:

(a) receive, or cause to be received, into the Gathering System, from or for the account of Shipper, at each Receipt Point, all Dedicated Production tendered by Shipper;

(b) compress and dehydrate Dedicated Gas received into the Gathering System at the System Compressor Stations;

(c) deliver, or cause to be delivered, to or for the account of Shipper, at the nominated Delivery Point for Gas, Delivery Point Gas allocated to Shipper; and

(d) make available for delivery, to or for the account of Shipper, at each Delivery Point for Liquid Hydrocarbons, the Liquid Hydrocarbons received into the Gathering System or into Gatherer's trucks and gathered to or delivered into storage tanks at such Delivery Point allocated to Shipper in accordance with Section 6.4.

Section 3.2 Development Plan; Gathering System Plan; Exchange and Review of Information.

(a) The Initial Development Plan describes the planned development, drilling, and production activities relating to the Dedicated Properties through the date that is 18 months after the Original Agreement Effective Date (such plan, as updated as hereinafter provided, and including any proposed development plan that becomes part of the Development Plan pursuant to Section 2.5(b), the "***Development Plan***"). Following the Original Agreement Effective Date, Shipper shall provide Gatherer an updated Development Plan describing the planned development, drilling, and production activities relating to the Dedicated Properties for the 18-Month period commencing on the date of such updated Development Plan on or before the last Day of each Month. Each Development Plan will include (i) information as to the Wells that Shipper expects will be drilled during such period (each such Well reflected in a Development Plan, a "***Planned Well***"), information as to each Well Pad expected to be constructed during such period (each such Well Pad reflected in a Development Plan, a "***Planned Well Pad***") and the approximate locations thereof, the earliest date on which one or more Wells at each such Well Pad are expected to be completed, and the Delivery Points at which Production produced from such Wells is to be redelivered to Shipper and (ii) good faith and reasonable production forecasts for all Wells connected as of, and estimated to be connected to the Gathering System during the 18-Month period following, the date of such Development Plan (to the extent not previously provided or, if earlier provided, as revised in Shipper's good faith estimation). Shipper shall make its representatives available to discuss the Development Plan from time to time with Gatherer and its representatives, in order to facilitate advance planning for expansion or improvement of the Gathering System and to address other matters relating to the construction and installation of additions to the Gathering System. Shipper may provide updated or amended Development Plans to Gatherer at any time and shall provide its then-current Development Plan to Gatherer from time to time on or prior to the fifth (5th) Business Day after Gatherer's request therefor.

(b) Attached hereto as Exhibit F is a Gathering System plan describing and/or depicting the Gathering System as of the Original Agreement Effective Date, including all pipelines, all Receipt Points and Delivery Points, and all compression and dehydration facilities and other major physical facilities, together with their locations, sizes and other physical specifications, operating parameters, capacities, and other relevant specifications, and together with a schedule for completing the construction and installation of the planned portions thereof, in each case as in existence, under construction, or planned as of the Original Agreement Effective Date (such plan, as updated as hereinafter provided, the "***Gathering System Plan***"). Based on the Development Plans and such other information about the expected development of the Dedicated Properties as shall be provided to Gatherer by or on behalf of Shipper, Gatherer shall periodically update the Gathering System Plan. Without limiting the generality of the foregoing, Gatherer shall ensure that the Gathering System Plan reflects each Monthly Development Plan not later than 30 Days after such Development Plan is delivered. Gatherer shall make the Gathering System Plan available for inspection by Shipper and its representatives from time to time and shall make representatives of Gatherer available to discuss the Gathering System Plan from time to time with Shipper and its representatives. Gatherer shall provide Shipper updates not less frequently than monthly on the progress of work on all facilities necessary to connect Planned Wells to the Gathering System and to connect the Gathering System to the Delivery Points as set forth in the then-current Gathering System Plan.

(c) The Parties recognize that the plans for the development of the Dedicated Properties set forth in the Development Plans, as well as all information provided by Shipper to Gatherer regarding its intentions with respect to the development of the Dedicated Properties, are subject to change and revision at any time at the discretion of Shipper, and that such changes may impact the timing, configuration, and scope of the planned activities of Gatherer. The exchange of such information and any changes thereto shall not give rise to any rights or liabilities as between the Parties except as expressly set forth in this Agreement, and Gatherer shall determine at its own risk the time at which it begins to work on and incur costs in connection with particular Gathering System expansion projects, including the acquisition of rights of way, equipment, and materials. Without limiting the generality of the foregoing, Shipper has no obligation to Gatherer under this Agreement to develop or produce any hydrocarbons from the Dedicated Properties or to pursue or complete any drilling or development on the Dedicated Properties, whether or not envisioned in the Development Plan.

Section 3.3 Expansion of Gathering System; Connection of Well Pads; Delivery Points.

(a) The Gathering System shall be designed, developed, and constituted for the purpose of providing Services as and when needed to support the upstream development of the Dedicated Properties, and Gatherer shall be obligated, at its sole cost and expense, subject to the provisions of this Agreement, to plan, procure, construct, install, own, and operate the Gathering System so as to timely connect the Planned Wells to the Gathering System, connect the Gathering System to Delivery Points on the Downstream Pipelines, at the Processing Plants, or other facilities specified by Shipper, and timely commence providing the full scope of Services, with respect to all Dedicated Production produced from the Planned Wells from and after their completion, all in accordance with this Section 3.3; *provided*, that the foregoing shall not preclude Gatherer from also designing, developing and constituting the Gathering System to accommodate Third Party Production.

(b) In planning the Gathering System, Gatherer shall use its discretion in determining when to construct and install separate and segregated facilities in the same geographical area for the purposes of handling Production with different characteristics (for example, hydrocarbon-dry versus hydrocarbon-wet Gas); provided, however, that if Shipper requests that Gatherer construct and install separate facilities, Gatherer shall, subject to all of the terms and conditions of this Agreement, do so.

(c) Gatherer shall be obligated to connect Wells at a particular Well Pad to the Gathering System only if Gatherer has received from Shipper a notice in the form of Exhibit G hereto (or in such form as Shipper and Gatherer shall otherwise agree from time to time) stating that Shipper intends to drill and complete such Wells at such Well Pad (as it may be amended as contemplated in Section 3.3(f), a "***Connection Notice***") and setting forth the target completion date for drilling and completion of such Wells (such date, as it may be amended as contemplated in Section 3.3(f), the "***Target Completion Date***"), and the expected production from such Well Pad over the next eighteen (18) months. Following receipt of a Connection Notice, Gatherer shall cause the necessary facilities to be constructed to connect the Planned Wells referred to in such Connection Notice to the Gathering System and to commence the Services with respect to Dedicated Production produced from such Planned Wells. Such facilities shall be available to receive Dedicated Production from Planned Wells on the Planned Well Pad on which such Planned Wells are to be located as soon as reasonably practicable following the Connection Notice and in any event on or before the later to occur of (1) the Target Completion Date with respect to such Planned Well Pad, (2) the date that is 180 Days after the Connection Notice, and (3) the date on which the initial Planned Well(s) at such Planned Well Pad has reached its projected depth and is ready for completion (the later of such dates, with respect to such Planned Well Pad, the "***Completion Deadline***"). Gatherer shall provide Shipper notice promptly upon Gatherer's becoming aware of any reason to believe that it may not be able to connect a Planned Well Pad to the Gathering System by the Target Completion Date therefor or to otherwise complete all facilities necessary to provide the full scope of Services with respect to all Dedicated Production from Wells on such Planned Well Pad by the Target Completion Date therefor. If and to the extent Gatherer is delayed in completing and making available such facilities by a Force Majeure event or any action of Shipper that is inconsistent with the cooperation requirements of Section 3.9, then the Completion Deadline for such connection shall be extended for a period of time equal to that during which Gatherer's completion and making available of such facilities was delayed by such events or actions. If such facilities are not completed and made available by the Completion Deadline, as Shipper's sole and exclusive remedies for such delay,

(i) the Dedicated Production from such Planned Well Pad shall be temporarily released from dedication hereunder until such time as such Planned Well Pad is connected to the Gathering System and the Gathering System is ready to receive Dedicated Production produced from such Planned Well Pad and to commence the Services with respect thereto; and

(ii) Shipper shall have the right to complete the procurement, construction and/or installation of any rights or facilities necessary to connect the relevant Planned Well Pad to the Gathering System, to connect the Gathering System to the relevant Delivery Point, and/or to permit Dedicated Production from Planned Wells at the Planned Well Pad to be received into the Gathering System and delivered to the relevant Delivery Point, in which case Gatherer shall pay to Shipper an amount equal to 115% of all reasonable costs and expenses incurred by Shipper in so procuring, constructing, and/or installing such rights and facilities, and Shipper shall convey all such rights and facilities to Gatherer and such rights and facilities shall thereafter be part of the Gathering System.

The remedies set forth in clauses (i) and (ii) above shall be applicable to Wells with Completion Deadlines that are 180 Days or more after the Original Agreement Effective Date.

(d) If the actual completion of the initial Planned Well at a particular Planned Well Pad is delayed more than 30 Days after the Target Completion Date for such Planned Well Pad and the Gathering System is connected to such Planned Well Pad and available to commence providing the Services with respect to all Dedicated Production from such Planned Well prior to the date such initial Planned Well has reached its projected depth and is ready for completion, Gatherer shall be entitled to a fee equal to interest per annum at the Wall Street Journal prime rate on the incremental cost and expense incurred by Gatherer to procure, construct and install the relevant rights and facilities to connect to such Planned Well Pad and to cause such facilities to be available to commence providing Services thereto for the number of Days after the Target Completion Date until the Day that the first Well at such Planned Well Pad is completed; provided, however, that if such first Well has not been completed by the date that is six months after the Target Completion Date for such Well or, as of an earlier date, Shipper notifies Gatherer that it has elected not to complete any Planned Wells at such Planned Well Pad, Shipper shall pay to Gatherer an amount equal to 115% of all reasonable incremental costs and expenses incurred by Gatherer in procuring, constructing and installing such rights and facilities to connect the Gathering System to such Planned Well Pad and to cause such facilities to be available to commence providing Services thereto, and Gatherer shall assign, transfer, and deliver to Shipper all rights and facilities (including equipment, materials, work in progress, and completed construction) the costs and expenses of which have so been paid by Shipper, to Shipper. If Shipper so pays Gatherer and later completes a Well at such Planned Well Pad, or if such facilities are later used to connect a completed Well at a different Planned Well Pad or for a third party, Gatherer shall refund to Shipper such amount paid by Shipper, and Shipper shall retransfer such rights and facilities to Gatherer.

(e) A Connection Notice shall be deemed to have been given for the Planned Wells set forth on Exhibit H hereto, the Target Completion Date for which shall be as set forth on Exhibit H. Such Connection Notice shall be deemed to have been given for each such Planned Well 180 Days prior to such Target Completion Date.

(f) Without limiting the rights and obligations of the Parties under Section 3.3(d), with respect to any Well Pad for which Shipper has delivered a Connection Notice (any such Well Pad for which a Delay Notice described below is provided, a "***Delayed Well Pad***", and such Connection Notice, the "***Original Connection Notice***" with respect to such Delayed Well Pad), Shipper may, by notice to Gatherer (a "***Delay Notice***"), inform Gatherer that the expected completion date for drilling and completion of the Wells on the Delayed Well Pad has been extended beyond the Target Completion Date for the Delayed Well Pad stated in the Original Connection Notice and that Shipper elects either to (1) amend the Original Connection Notice for the Delayed Well Pad by changing the Target Completion Date to a date specified in such Delay Notice, in which case the Completion Deadline shall be determined as set forth in Section 3.3(c) based on the date of delivery of the Original Connection Notice but utilizing the Target Completion Date as so amended, or (2) withdraw the Original Connection Notice. If Shipper elects to withdraw the Original Connection Notice, and if a new Connection Notice is later delivered with respect to the Delayed Well Pad, Gatherer shall cause the necessary facilities to be constructed to connect Wells to the Gathering System and to commence the Services with respect Dedicated Production from such Wells as provided in this Agreement based on the new Connection Notice, with the Completion Deadline being determined based on the date of delivery of the new Connection Notice and the Target Completion Date set forth therein, as though the Original Connection Notice was never given. In the case of either (1) or (2) above:

(i) If the completion of the initial Well on the Delayed Well Pad has not occurred by the 31st day after the original Target Completion Date with respect to the Delayed Well Pad as set forth in the Original Connection Notice, Shipper shall pay Gatherer a fee equal to interest per annum at the Wall Street Journal prime rate on the Incurred Costs with respect to such Delayed Well Pad. Such fee shall be payable Monthly in arrears on the 15th day of each Month for the period commencing on such 31st day through the earlier to occur of (A) the date on which the Incurred Costs are paid in full to Gatherer as contemplated under Section 3.3(f)(ii) and (B) the date on which the initial Well on the Delayed Well Pad has been completed pursuant to an applicable Connection Notice.

(ii) If (A) the completion of the initial Well on the Delayed Well Pad has not occurred pursuant to an applicable Connection Notice by the date that is six months after the original Target Completion Date with respect to the Delayed Well Pad as set forth in the Original Connection Notice (the "***Six Month Deadline***"), or (b) Shipper gives notice to Gatherer that it has determined to permanently cancel all Planned Wells at the Delayed Well Pad, Shipper shall pay to Gatherer an amount equal to 115% of the Incurred Costs. Such payment shall be due on the 15th day after the Six Month Deadline. On or before the 30th day after delivery of written request from Shipper to Gatherer at any time on or after the date such payment is made, Gatherer shall assign, transfer, and deliver to Shipper all rights and facilities (including equipment, materials, work in progress, and completed construction) the costs and expenses of which have so been paid by Shipper as part of the Incurred Costs, to Shipper. If Shipper so pays Gatherer and later completes a Well at such Well Pad, or if such facilities are later used to connect and provide Services to a Well at a different Planned Well Pad or to provide services for a third party, Gatherer shall refund to Shipper such amount paid by Shipper, and Shipper shall upon receipt of payment therefor, if applicable, retransfer such rights and facilities to Gatherer.

"***Incurred Costs***" means, with respect to a Delayed Well Pad and the delivery of the Original Connection Notice therefor, the amount of all reasonable incremental costs and expenses incurred by Gatherer through the date of the Delay Notice for such Delayed Well Pad to procure, construct and install the relevant rights and facilities to connect the Delayed Well Pad to the Gathering System and to cause such facilities to be available to commence providing Services thereto.

(g) Shipper shall have right to specify in the Development Plan or in a Connection Notice that Dedicated Production produced from a particular Well be redelivered to Shipper at a particular Delivery Point, including a Delivery Point on any Downstream Pipeline. Gatherer shall be obligated, at Gatherer's cost, to provide connections to the Delivery Points set forth on Exhibit B. If Shipper specifies that Shipper's Production is to be delivered to a Delivery Point not described on Exhibit B that is not at such time connected to the Gathering System, Gatherer shall, at Shipper's sole cost, risk, and expense, provide a connection to such Delivery Point. All such Delivery Points shall be provided with all interconnection facilities and other Delivery Point facilities (including any Measurement Facilities), and with sufficient capacities, necessary to permit Shipper's Production to be redelivered at such Delivery Point in accordance with this Agreement (with all expansions of capacity at such Delivery Points, including the Delivery Points described on Exhibit B, being at Shipper's sole, cost, risk, and expense). Subject to the foregoing, Gatherer shall connect each Well to the Gathering System such that Production from such Well can be redelivered to the Delivery Point described in the Development Plan.

Section 3.4 Compression.

(a) The Gathering System Plan will describe the compression facilities that will be required to compress Dedicated Gas upstream of the Delivery Points or any System High Pressure Line in order for the Gathering System to be operated at the pressures specified in Section 8.1 and to permit Dedicated Gas to enter the facilities of the Downstream Pipelines or Processing Plants, as applicable ("***Required Compressor Stations***"). Gatherer shall install each such Required Compressor Station as directed by Shipper and shall operate and maintain each Required Compressor Station (each such Required Compressor Station so installed by Gatherer, a "***System Compressor Station***"). Notwithstanding the foregoing, Gatherer shall not be obligated to install any Required Compressor Station during the ten year period immediately prior to the scheduled termination of this Agreement unless Shipper agrees that this Agreement shall remain in effect beyond the scheduled termination thereof as to such Required Compressor Station only and the amount determined under Section 5.1(d)(ii)(A) with respect thereto until the 10th anniversary of the placement in service of such Required Compressor Station. To the extent that Shipper does not direct Gatherer to install any Required Compressor Station as, when, and where described in the Gathering System Plan and as a consequence the Gathering System is not capable of operating in accordance with the obligations of Gatherer with respect to pressures that are set forth in Sections 8.1 and 8.2, Gatherer shall be relieved from such obligations. For the avoidance of doubt, Gatherer shall have the right at any time to add additional compressor stations to the Gathering System, and to add compression capacity at any System Compressor Station in addition to the capacity that Shipper has directed to be installed at such System Compressor Station, as it deems necessary or appropriate to provide the Services and such services as it is providing in respect of Third Party Production. Shipper must pay the Compression Fee with respect to all its Gas that is compressed using such additional compressor stations or using such additional capacity, but such additional compressor stations or additional capacity shall not be included for purposes of calculating the Minimum Compression Volume Commitment, and the Compression Fee paid by Gatherer for its Gas compressed using such additional compressor stations or additional capacity shall not count toward the amount determined under Section 5.1(d)(ii)(A).

(b) The Parties acknowledge that inlet Measurement Facilities and a slug catcher have not been installed at the System Compressor Station referred to in the Initial Gathering Plan as the Bluestone Compressor Station. Shipper agrees that if it sells or otherwise transfers any Well upstream of the Bluestone Compressor Station such that Gas owned by a third party is being gathered to the Bluestone Compressor Station, Gatherer will install such Measurement Facilities and a slug catcher at the Bluestone Compressor Station, and Shipper will reimburse Gatherer's reasonable costs of doing so.

Section 3.5 High Pressure Services. The Gathering System Plan will describe the High Pressure gathering pipelines that Gatherer determines are necessary or appropriate to connect the Gathering System to the Gas Delivery Points required by Shipper and to redeliver the volumes of Dedicated Gas to be redelivered at such Delivery Points in the most efficient manner ("***Required High Pressure Lines***"). Gatherer shall install each such Required High Pressure Line, together with the associated Required Compressor Stations, as directed by Shipper and shall operate and maintain each Required High Pressure Line (each such Required High Pressure Line so installed by Gatherer, a "***System High Pressure Line***"). Notwithstanding the foregoing, Gatherer shall not be obligated to install any Required High Pressure Line during the ten year period immediately prior to the scheduled termination of this Agreement unless Shipper agrees either that this Agreement shall remain in effect beyond the scheduled termination thereof as to such Required High Pressure Line only and the amount determined under Section 5.1(d)(i)(A) with respect thereto until the 10th anniversary of the placement in service of such Required High Pressure Line. To the extent that Shipper does not direct Gatherer to install any Required High Pressure Line as, when, and where described in the Gathering System Plan and as a consequence the Gathering System is not capable of operating in accordance with the obligations of Gatherer with respect to pressures that are set forth in Sections 8.1 and 8.2, Gatherer shall be relieved from such obligations. For the avoidance of doubt, Gatherer shall have the right at any time to add additional High Pressure gathering pipelines to the Gathering System as it deems necessary or appropriate to provide the Services and such services as it is providing in respect of Third Party Production. Shipper must pay the High Pressure Gathering Fee with respect to all its Gas that is gathered through such additional High Pressure gathering pipelines, but such additional High Pressure Gathering Pipelines shall not be included for purposes of calculating the Minimum High Pressure Volume Commitment, and the High Pressure Gathering Fee paid by Gatherer for its Gas gathered through such additional High Pressure gathering pipelines shall not count toward the amount determined under Section 5.1(d)(i)(A).

Section 3.6 Liquids Gathering. Shipper is responsible for the construction, ownership, and operation of (a) all facilities for the separation and/or collection of Liquid Hydrocarbons at the wellhead and the Well site storage of such liquids and (b) the pumps located at each Receipt Point to transfer Liquid Hydrocarbons from such storage into the Gathering System or into Gatherer's trucks. Shipper shall ensure that pumps have sufficient capacity and are operated in a manner sufficient to cause the Liquid Hydrocarbons received into the Gathering System to be redelivered into the tanks located at the Liquid Hydrocarbons Delivery Points. Shipper shall cause Liquid Hydrocarbons to be received into the Gathering System at reasonably uniform rates of flow and to provide Gatherer reasonable notice of material increases or decreases in such rates of flow. To the extent that any facilities for the stabilization of such Liquid Hydrocarbons are required at the Liquid Hydrocarbons Delivery Points, Gatherer will provide such facilities and required stabilization services to Shipper on a cost-of-service basis as provided in Section 5.1(e).

Section 3.7 Production Removed for Lease Operations. Gatherer shall use commercially reasonable efforts to accommodate, at the cost and expense of Shipper, any request by Shipper to redeliver to Shipper any Production that has been received into the Gathering System that Shipper desires to use in lease operations, including for drilling and fractionation fuel. Shipper shall be responsible for the construction, ownership, and operation of facilities to transport such Production from the point of redelivery of such production from the Gathering System to the lease sites where such Production will be used.

Section 3.8 Right of Way and Access. Gatherer is responsible for the acquisition of rights of way, crossing permits, licenses, use agreements, access agreements, leases, fee parcels, and other rights in land right necessary to construct, own, and operate the Gathering System, and all such rights in land shall be solely for use by Gatherer and shall not be shared with Shipper, except as otherwise agreed by Gatherer; provided that Shipper hereby grants, without warranty of title, either express or implied, to the extent that it has the right to do so without the incurrence of material expense, an easement and right of way upon all lands covered by the Dedicated Properties, for the purpose of installing, using, maintaining, servicing, inspecting, repairing, operating, replacing, disconnecting, and removing all or any portion of the Gathering System, including all pipelines, meters, and other equipment necessary for the performance of this Agreement; provided, further, that the exercise of these rights by Gatherer shall not unreasonably interfere with Shipper's lease operations or with the rights of owners in fee, and will be subject to Shipper's safety and other reasonable access requirements applicable to Shipper's personnel. Shipper shall not have a duty to maintain the underlying agreements (such as leases, easements, and surface use agreements) that such grant of easement or right of way to Gatherer is based upon, and such grants of easement or right of way will terminate if Shipper loses its rights to the property, regardless of the reason for such loss of rights. Notwithstanding the foregoing, (i) Shipper will assist Gatherer to secure replacements for such terminated grants of easement or right of way, in a manner consistent with the cooperation requirements of Section 3.9, (ii) to the extent that Shipper agrees that Gatherer's Measurement Facilities may be located on Shipper's Well Pad sites, Shipper shall be responsible for obtaining any necessary rights to locate such Measurement Facilities on such Well Pad sites, and (iii) Shipper shall use reasonable efforts to involve Gatherer in Shipper's negotiations with the owners of lands covered by the Dedicated Properties so that Shipper's surface use agreements and Gatherer's rights of way with respect to such lands can be concurrently negotiated and obtained.

Section 3.9 Cooperation. Because of the interrelated nature of the actions of the Parties required to obtain the necessary permits and authorizations from the appropriate Governmental Authorities and the necessary consents, rights of way and other authorizations from other Persons necessary to drill and complete each Planned Well and construct the required extensions of the Gathering System to each Planned Well Pad, the Parties agree to work together in good faith to obtain such permits, authorizations, consents and rights of way as expeditiously as reasonably practicable, all as provided herein. The Parties further agree to cooperate with each other and to communicate regularly regarding their efforts to obtain such permits, authorizations, consents and rights of way.

ARTICLE 4
TERM

Section 4.1 Term. This Agreement shall become effective on the Effective Date and, unless terminated earlier by mutual agreement of the Parties, shall continue in effect until the twenty-fourth (24th) anniversary of the Original Agreement Effective Date and from year to year thereafter (with the initial term of this Agreement deemed extended for each of any such additional year) until such time as this Agreement is terminated, effective upon an anniversary of the Original Agreement Effective Date, by notice from either Party to the other Party on or before the one hundred eightieth (180th) Day prior to such anniversary.

ARTICLE 5
FEES AND CONSIDERATION

Section 5.1 Fees.

(a) Subject to the other provisions of this Agreement, including Section 5.1(d), Shipper shall pay Gatherer each Month in accordance with the terms of this Agreement, for all Services provided by Gatherer during such Month, an amount equal to the sum of the following:

(i) The product of (A) the aggregate volume of Gas, stated in Mcf, received by Gatherer from Shipper or for Shipper's account at each Receipt Point during such Month multiplied by (B) $0.30 (provided that such fee shall be discounted by fifty percent (50%) for Gas removed from the Gathering System for use lease operations fuel in accordance with Section 3.7) (as such fee may be increased or decreased in accordance with Section 5.1(b), the "***Gathering Fee***");

(ii) The product of (A) the aggregate volume of Gas, stated in Mcf, received from Shipper or for Shipper's account entering any System High Pressure Line during such Month multiplied by (B) $0.18 (as may be increased or decreased in accordance with Section 5.1(b), the "***High Pressure Gathering Fee***");

(iii) The product of (A) the aggregate volume of Gas, stated in Mcf, received from Shipper or for Shipper's account and compressed and dehydrated at each System Compressor Station during such Month multiplied by (B) $0.18 (as may be increased or decreased in accordance with Section 5.1(b), the "***Compression Fee***"); and

(iv) The product of (A) the aggregate volume of Liquid Hydrocarbons, stated in Barrels, received from Shipper or for Shipper's account entering the Gathering System or loaded into Gatherer's trucks during such Month multiplied by (B) $4.00 (as may be increased or decreased in accordance with Section 5.1(b), the "***Liquids Gathering Fee***").

(b) Effective on January 1 of each of 2014, 2015, 2016, 2017, and 2018, one hundred percent (100%), and on January 1, 2019, and each January 1 thereafter, fifty-five percent (55%), of the Gathering Fee, High Pressure Gathering Fee, Compression Fee, and Liquids Gathering Fee shall be adjusted up or down on an annual basis in proportion to the percentage change, from the preceding year, in the All Items Consumer Price Index for All Urban Consumers (CPI-U) for the U.S. City Average, 1982-84 = 100, as published by the United States Department of Labor, Bureau of Labor Statistics ("***CPI***"). Such adjustment shall reflect the percentage change in the CPI as it existed for June of the preceding calendar year from the CPI for the second immediately preceding June; *provided, however*, that the Gathering Fee, High Pressure Gathering Fee, Compression Fee, and Liquids Gathering Fee shall never be less than the initial fees stated in Section 5.1(a); nor shall such fees be increased or decreased by more than 3% in any given year.

(c) Subject to the other provisions of this Agreement, including Section 5.1(d), Shipper shall pay Gatherer the actual cost of electricity used as Fuel and allocated to Shipper in accordance with Section 6.2.

(d) Notwithstanding the foregoing provisions of this Section 5.1; regardless of whether Shipper has any Firm Capacity Production:

(i) If, with respect to any Contract Year in which there is a Minimum High Pressure Volume Commitment, Shipper shall pay to Gatherer, on or before the 30th Day after receipt of Gatherer's invoice therefor (which shall be delivered not more than sixty (60) Days after the end of the relevant Contract Year), an amount equal to the excess, if any, of:

(A) the product of the Minimum High Pressure Volume Commitment for such Contract Year multiplied by the High Pressure Gathering Fee in effect for such Contract Year, over

(B) the product of the High Pressure Gathering Fee in effect for such Contract Year multiplied by the aggregate of the volumes of Dedicated Production, stated in Mcf, delivered or Made Available for Delivery at each System High Pressure Line during such Contract Year.

(ii) If, with respect to any Contract Year in which there is a Minimum Compression Volume Commitment, Shipper shall pay to Gatherer, on or before the 30th Day after receipt of Gatherer's invoice therefor (which shall be delivered not more than sixty (60) Days after the end of the relevant Contract Year), an amount equal to the excess, if any, of:

(A) the product of the Minimum Compression Volume Commitment for such Contract Year multiplied by the Compression Fee in effect for such Contract Year, over

(B) the product of the Compression Fee in effect for such Contract Year multiplied by the aggregate of the volumes of Dedicated Production, stated in Mcf, delivered or Made Available for Delivery at each System Compressor Station during such Contract Year.

(e) All Services for which specific prices are not set forth in Section 5.1(a), including any required treating of Production, the handling and treatment of Condensate recovered from the Gathering System, and the stabilization of Liquid Hydrocarbons, shall be priced on a cost of service basis as set forth in this Section 5.1(e). In addition, notwithstanding the foregoing provisions of this Section 5.1 or any other provision to the contrary in this Agreement, Gatherer shall have the right to elect to be paid for some or all Services, on a cost of service basis to the extent set forth in this Section 5.1(e). Gatherer shall have the right to elect to be paid on a cost of service basis (i) for any Services other than Services offered in respect of the Wells and Planned Wells set forth in the Initial Development Plan, all of which Services shall be performed for the volumetric fees, subject to the minimum volumes, set forth in Section 5.1(a) and Section 5.1(d), and (ii) any compression services in respect of the Wells and Planned Wells set forth in the Initial Development Plan if Gatherer determines in good faith that, if such services were to be performed for the volumetric fees, and subject to the minimum volumes, set forth in Section 5.1(a) and Section 5.1(d), it would receive a rate of return on its capital expenditures for such System Compressor Station of less than 13% over the period of 84 months after such System Compressor Station is placed into service. With respect to such Services, Gatherer may elect, by notice to Shipper at least three (3) Months prior to the placement in service of the relevant facilities or parts of the Gathering System, or, in the case of any gathering facilities by Gatherer acquired pursuant to Section 2.5(a), in the notice given by Gatherer in accordance with such Section that Gatherer will acquire such gathering facilities, to be paid on a cost of service basis for the Services specified in such notice commencing with their placement in service or with the acquisition of such facilities, as applicable, and continuing for the remaining term of this Agreement, but only with respect to the facilities so acquired and/or discrete parts of the Gathering System (each, a "***CS Facility***") that are placed into service after such notice. The Services specified in such notice may be of any scope determined by Gatherer in its sole discretion and may include all eligible Services or any part thereof and may include, by way of example only, gathering Services with respect to a particular Well or group of Wells, compression Services and/or High Pressure Services with respect to a particular System Compressor Station and/or System High Pressure Line, all Services of a particular type, and any other subset of the Services determined by Gatherer, in each case subject to the foregoing sentence. All Services provided from time to time on a cost of service basis shall be bundled together for purposes of calculating a single Monthly cost of service fee (the "***Cost of Service Fee***"), which shall be calculated with respect to each Contract Year as set forth in Exhibit I attached hereto.

Section 5.2 Fee Rebates.

(a) With respect of each calendar quarter beginning on January 1, 2020 and ending December 31, 2023, Gatherer shall pay Shipper a rebate (as calculated below) (each, a "***Fee Rebate***") on the Gathering Fees for the applicable quarter. Any Fee Rebate shall be included in the invoice delivered by Gatherer for the last month of each such calendar quarter and credited against amounts owed by Shipper to Gatherer for the Gathering Fees in the last month of such calendar quarter. If the Fee Rebate is more than the amounts owed by Shipper to Gatherer for the Gathering Fees in the last month of the applicable quarter, then the excess Fee Rebate shall roll over and be credited against amounts owed by Shipper to Gatherer for the Gathering Fees in the next subsequent month(s) until such Fee Rebate credit is fully utilized.

(b) If the Average Quarterly Receipt Point Volumes for the first calendar quarter of 2020 are equal to or greater than 2,700 MMcf, then the Fee Rebate for such calendar quarter shall equal Twelve Million Dollars ($12,000,000). If the Average Quarterly Receipt Point Volumes for the first calendar quarter of 2020 are less than 2,700 MMcf, then the Fee Rebate for such calendar quarter shall equal Zero Dollars ($0).

(c) If the Average Quarterly Receipt Point Volumes for the second calendar quarter of 2020 are equal to or greater than 2,700 MMcf, then the Fee Rebate for such calendar quarter shall equal Twelve Million Dollars ($12,000,000). If the Average Quarterly Receipt Point Volumes for the second calendar quarter of 2020 are less than 2,700 MMcf, then the Fee Rebate for such calendar quarter shall equal Zero Dollars ($0).

(d) If the Average Quarterly Receipt Point Volumes for the third calendar quarter of 2020 are equal to or greater than 2,800 MMcf, then the Fee Rebate for such calendar quarter shall equal Twelve Million Dollars ($12,000,000). If the Average Quarterly Receipt Point Volumes for the third calendar quarter of 2020 are less than 2,800 MMcf, then the Fee Rebate for such calendar quarter shall equal Zero Dollars ($0).

(e) If the Average Quarterly Receipt Point Volumes for the fourth calendar quarter of 2020 are equal to or greater than 2,900 MMcf, then the Fee Rebate for such calendar quarter shall equal Twelve Million Dollars ($12,000,000). If the Average Quarterly Receipt Point Volumes for the fourth calendar quarter of 2020 are less than 2,900 MMcf, then the Fee Rebate for such calendar quarter shall equal Zero Dollars ($0).

(f) For each calendar quarter in 2021, 2022 and 2023, (i) if the Average Quarterly Receipt Point Volumes for such calendar quarter are less than 2,900 MMcf, then the Fee Rebate for such calendar quarter shall equal Zero Dollars ($0), (ii) if the Average Quarterly Receipt Point Volumes for such calendar quarter are equal to or greater than 2,900 MMcf, but less than 3,150 MMcf, then the Fee Rebate for such calendar quarter shall equal Twelve Million Dollars ($12,000,000), (iii) if the Average Quarterly Receipt Point Volumes for such calendar quarter are equal to or greater than 3,150 MMcf, but less than 3,400 MMcf, then the Fee Rebate for such calendar quarter shall equal Fifteen Million Five Hundred Thousand Dollars ($15,500,000), and (iv) if the Average Quarterly Receipt Point Volumes for such calendar quarter are equal to or greater than 3,400 MMcf, then the Fee Rebate for such calendar quarter shall equal Nineteen Million Dollars ($19,000,000).

ARTICLE 6
ALLOCATIONS

Section 6.1 Allocation of Lost and Unaccounted For Gas. Lost and Unaccounted For Gas shall be allocated, on a Monthly basis, among all Receipt Points on each System Segment pro rata based upon the Thermal Content of all Gas received at all System Receipt Points on such System Segment during such Month. Total Lost and Unaccounted For Gas with respect to each System Segment shall be determined by subtracting from the sum of the total Thermal Content of Gas received at all System Receipt Points on such System Segment during such Month the sum of (i) the Thermal Content of Gas actually delivered to all System Delivery Points on such System Segment during such Month, (ii) the Thermal Content of Condensate recovered from such System Segment during such Month (other than Condensate vaporized and reinjected into the Gas stream), and (iii) the Thermal Content of Gas used for Fuel on such System Segment, if any, during such Month. Lost and Unaccounted For Gas shall be allocated, on a Monthly basis, to each Receipt Point based upon a fraction, the numerator of which is the total Thermal Content of Gas measured at such Receipt Point during such Month, and the denominator of which is the total Thermal Content of Gas measured at all System Receipt Points on the System Segment on which such Receipt Point is located during such Month.

Section 6.2 Allocation of Fuel. Gatherer shall allocate Fuel (included Gas used as Fuel and the cost of electricity used as Fuel), on a Monthly basis, to each Receipt Point upstream of a System Compressor Station on a pro rata basis, based upon a fraction, the numerator of which is the total volume of Gas measured at such Receipt Point during such Month, and the denominator of which is the total volume of Gas measured at all System Receipt Points upstream of such System Compressor Station during such Month. Gas consumed for Fuel shall be determined based actual measurements of Fuel consumption.

Section 6.3 Allocation of Condensate Recovered from the Gathering System. Gatherer shall allocate the volume of Condensate collected from any System Segment (or from facilities at compressor stations downstream of System Delivery Points on such System Segment and allocated to the Gathering System by the operator of such compressor station) to each System Receipt Point on such System Segment during the applicable Month based on a fraction, the numerator of which is the theoretical volume of Condensate attributable to such System Receipt Point during such Month and the denominator of which is the total theoretical volume of Condensate for all such System Receipt Points on such System Segment during such Month. The theoretical volume of Condensate at each System Receipt Point shall be determined by multiplying the total volume of Gas (in Mcf) received at the applicable System Receipt Point during the applicable Month by the Gallons per Mcf of pentanes and heavier components in such Gas determined at the relevant System Receipt Point on such System Segment.

Section 6.4 Allocation of Liquid Hydrocarbons.

(a) Subject to Section 6.4(b), Gatherer shall allocate the volume of Liquid Hydrocarbons gathered to or delivered into storage tanks at each Delivery Point to each System Receipt Point upstream of such Delivery Point during the applicable Month based on a fraction, the numerator of which is the volume of Liquid Hydrocarbons received at such System Receipt Point and the numerator of which is the total volumes of Liquid Hydrocarbons received at all such System Receipt Points during such Month.

(b) Gatherer shall not commingle Shipper's Liquid Hydrocarbons received at the Receipt Points with Liquid Hydrocarbons constituting Third Party Production if the resulting commingled stream would have a market value that is materially less than the market value a stream composed solely of Shipper's Liquid Hydrocarbons would have, unless Gatherer has provided by notice to Shipper a written allocation methodology that ensures that Shipper is allocated a portion of the commingled stream that would enable it to realize a market value that reasonably approximates the market value of such stream composed solely of Shipper's Liquid Hydrocarbons. From and after the delivery of such notice, Gatherer shall have the right to commingle such Liquid Hydrocarbons and shall apply such allocation methodology to such commingled stream.

ARTICLE 7
CERTAIN RIGHTS AND OBLIGATIONS OF PARTIES

Section 7.1 Operational Control of Gatherer's Facilities. Gatherer shall design, construct, own, operate, and maintain the Gathering System at its sole cost and risk. Gatherer shall be entitled to full and complete operational control of its facilities and shall be entitled to schedule deliveries and to operate and reconfigure its facilities in a manner consistent with its obligations under this Agreement.

Section 7.2 Maintenance. Gatherer shall be entitled, without liability, to interrupt its performance hereunder to perform necessary or desirable inspections, pigging, maintenance, testing, alterations, modifications, expansions, connections, repairs or replacements to its facilities as Gatherer deems necessary ("***Maintenance***"), with reasonable notice provided to Shipper, except in cases of emergency where such notice is impracticable or in cases where the operations of Shipper will not be affected. Before the beginning of each calendar year, Gatherer shall provide Shipper in writing with a projected schedule of the Maintenance to be performed during the year and the anticipated date of such Maintenance. On or before the 10th Day before the end of each Month, Gatherer shall provide Shipper with its projected maintenance schedule for the following Month.

Section 7.3 Firm Capacity Production; Capacity Allocations on the Gathering System. Subject to the capacity allocations set forth in this Section 7.3, Gatherer has the right to contract with other Persons for the delivery of Third Party Production to the Gathering System, including the delivery of Firm Capacity Production. If the volume of Gas or Liquid Hydrocarbons, as applicable, available for delivery into any System Segment exceeds the capacity of such System Segment at any point relevant to Gatherer's service to Shipper hereunder, then Gatherer shall interrupt or curtail receipts of Production in accordance with the following:

(a) *First*, Gatherer shall curtail all Interruptible Production prior to curtailing Firm Capacity Production.

(b) *Second*, if additional curtailments are required beyond Section 7.3(a) above, Gatherer shall curtail Firm Capacity Production. In the event Gatherer curtails some, but not all Firm Capacity Production on a particular Day, Gatherer shall allocate the capacity of the applicable point on the relevant System Segment available to such shippers of Firm Capacity Production, including Dedicated Production, on a pro rata basis based upon Shipper's and the other shippers' of Firm Capacity Production average of the confirmed nominations for the previous fourteen (14) Day period of Firm Capacity Production prior to the event causing the curtailment.

Section 7.4 Arrangements After Redelivery. It shall be Shipper's obligation to make any required arrangements with other parties for delivery of Shipper's Production to the Receipt Points and Delivery Point Gas and Liquid Hydrocarbons following delivery by Gatherer at the Delivery Points.

Section 7.5 Line Pack. To the extent that it is necessary, in order for Gatherer to commence operations of new segments of the Gathering System, for Production to be used as line fill, Shipper shall provide such line fill to Gatherer.

ARTICLE 8
PRESSURES AT RECEIPT POINTS AND DELIVERY POINTS

Section 8.1 Pressures at Receipt Points. Gatherer shall not operate the Gas Gathering System in such a manner as to cause the average pressure at any Receipt Point in any Month to exceed the lower of (a) two hundred (200) psig and (b) fifty (50) psig above the average suction pressure, as measured at the first separator or slug catcher upstream of any compression suction valve or any other valve that can be partially closed, at the nearest System Compressor Station downstream of such Receipt Point during such Month. Subject to the foregoing, Shipper shall deliver or cause to be delivered Gas to each Receipt Point at sufficient pressure to enter the Gathering System against its operating pressure.

Section 8.2 Pressures at Delivery Points. All System Compressor Stations (a) shall be designed for a suction pressure of from one hundred (100) psig to one hundred forty (140) psig and (b) shall be designed for and shall be operated at a discharge pressure sufficient to effect delivery to the relevant Downstream Pipeline or Processing Plant.

Section 8.3 Shipper Facilities. Shipper, at its own expense, shall construct, equip, maintain, and operate all facilities (including separation, line heaters, and/or compression equipment) necessary to deliver Dedicated Production to Gatherer at the Receipt Points. Shipper shall install and maintain sufficient pressure regulating equipment upstream of the Receipt Points in order to keep the pressure of the Gas delivered to Gatherer at the Receipt Points from exceeding the maximum allowable operating pressure at the applicable Receipt Point. Gatherer shall design the Gas Gathering System to ANSI 300 standards or higher such that the maximum allowable operating pressure at each Receipt Point shall be not less than 740 psig.

ARTICLE 9
NOMINATION AND BALANCING

Section 9.1 Gatherer Notifications. On or before the fifth (5th) Day prior to the end of each Month, Gatherer shall provide written notice to Shipper of Gatherer's good faith estimate of any capacity allocations or curtailments for the any System Segment, if any, that, based on then currently available information, Gatherer anticipates will be required or necessary during the next Month, including as a result of any Maintenance. Gatherer shall use all reasonable efforts to provide 48 hours advance notice of any actual event requiring allocation or curtailment, including Maintenance.

Section 9.2 Nominations. On or before the second (2nd) Day prior to the end of each Month, Shipper shall provide to Gatherer nominations for deliveries of Dedicated Production to the Receipt Points and the delivery of Delivery Point Gas and Liquid Hydrocarbons to the specified Delivery Points during the next Month. Shipper shall have the right to change such nominations at any time subject to the requirements of the Persons receiving Delivery Point Gas or Liquid Hydrocarbons at or downstream of the Delivery Points and subject to changes in wellhead volumes being delivered into the system.

Section 9.3 Balancing. Gatherer will maintain records of any Daily and Monthly variances ("***Imbalances***") between the volume of Dedicated Gas received at the Receipt Points and the volumes of Delivery Point Gas, plus Lost and Unaccounted for Gas, Fuel, and Condensate allocated to Shipper. Shipper shall make such changes in its nominations as Gatherer may from time to time reasonably request to maintain Daily and Monthly balances or to correct an Imbalance. Shipper shall reimburse Gatherer for any cost, penalty, or fee arising from any Imbalance assessed against Gatherer by any Person receiving Dedicated Production downstream of the Delivery Points, except to the extent such Imbalance was caused by Gatherer.

Upon the termination of this Agreement or at such other time as the Parties agree the Parties shall cash out any cumulative Imbalance using the applicable Index Price for the prior Month.

ARTICLE 10
QUALITY

Section 10.1 Receipt Point Gas Quality Specifications. Gas delivered by Shipper to the Receipt Points shall meet the following specifications (collectively, the "***Gas Quality Specifications***"):

(a) The Gas shall not contain any of the following in excess of: one-quarter (1/4) grain of hydrogen sulfide per hundred (100) cubic feet; one (1) grain of total sulfur per hundred (100) cubic feet; two one-hundredths of one percent (0.02%) by volume of oxygen; or two percent (2%) by volume of nitrogen.

(b) The total of all non-hydrocarbon gases shall not exceed three percent (3%) by volume.

(c) The temperature of the Gas at the Receipt Point shall not be in excess of one hundred twenty (120) degrees Fahrenheit.

(d) The Gas shall be free of solids, sand, salt, dust, gums, crude oil, and hydrocarbons in the liquid phase, and other objectionable substances which may be injurious to pipelines or which may interfere with the measurement, transmission or commercial utilization of said Gas.

Except for items (a) through (d) above, such Gas shall meet the most restrictive quality specifications required from time to time by the Downstream Pipelines receiving Delivery Point Gas, except for water vapor content, for which there shall be no specification applicable at the Receipt Points.

Section 10.2 Non-Conforming Gas. If any Gas delivered by Shipper fails at any time to conform to the Gas Quality Specifications, then Gatherer will have the right to immediately discontinue receipt of such non-conforming Gas so long as such Gas continues to be non-conforming. Shipper agrees to undertake commercially reasonable measures to eliminate the cause of such non-conformance. If Shipper fails to remedy such non-conformance, but such Gas conforms to all specifications other than hydrocarbon dew point and/or Gross Heating Value, then Gatherer agrees to (i) use commercially reasonable efforts to blend and commingle such Gas with other Gas in the Gathering System so that it meets the applicable specifications and (ii) if such Gas cannot be brought into compliance with such blending will continue to accept and redeliver such Gas to the Delivery Points that will accept such non-conforming Gas as long as (A) no harm is done to the Gathering System, (B) no harm is done to other shippers or their Gas, and (C) other shippers are not prevented from nominating Gas to their preferred Delivery Point. In the event that Gatherer takes receipt of non-conforming Gas, Shipper agrees to be responsible for, and to defend, indemnify, release, and hold Gatherer and its Affiliates, directors, officers, employees, agents, consultants, representatives, and invitees harmless from and against, all claims and losses of whatever kind and nature resulting from such non-conforming Gas.

Section 10.3 Delivery Point Gas Quality Specifications. Gatherer shall redeliver the Delivery Point Gas that it is required to redeliver to Shipper at the Delivery Points meeting the Gas Quality Specifications, provided that Shipper delivers Gas to Gatherer at the Receipt Points which meets the Gas Quality Specifications.

Section 10.4 Liquid Hydrocarbons Quality Requirements. Liquid Hydrocarbons delivered by Shipper to the Receipt Points shall have gravity, viscosity, and other properties such that it is readily susceptible to gathering and handling through Gatherer's existing facilities and such that it will not adversely affect the quality of Liquid Hydrocarbons received from other shippers or cause any material disadvantage to other shippers or Gatherer. If any Liquid Hydrocarbons delivered by Shipper fails at any time to conform to the foregoing requirements, then Gatherer will have the right to immediately discontinue receipt of such non-conforming Liquid Hydrocarbons so long as such Liquid Hydrocarbons continues to be non-conforming. Shipper agrees to undertake commercially reasonable measures to eliminate the cause of such non-conformance. Gatherer shall ensure that the Liquid Hydrocarbons of other shippers are also required to meet the foregoing standards.

Section 10.5 Greenhouse Gas Emissions. Notwithstanding anything contained in this Agreement to the contrary, in the event there is an enactment of, or change in, any law after the Original Agreement Effective Date which, in Gatherer's reasonable determination, results in (a) a Governmental Authority requiring Gatherer to hold or acquire emission allowances or their equivalent related to the carbon dioxide content or emissions or the greenhouse gas content or emissions attributable to Shipper's Production and/or the gathering, or transportation of such Production (collectively, "***Shipper's GHG Emissions***") or (b) Gatherer incurring any costs or expenses attributable to Shipper's Production, including any costs or expenses for disposal or treating of carbon dioxide attributable to such Production, or any other additional economic burden being placed on Gatherer in connection with or related to Shipper's GHG Emissions, including any tax, assessment, or other cost or expense (collectively, "***Emissions Charges***"), then (i) Shipper will use reasonable efforts to provide any required emissions allowances or their equivalent to Gatherer in a timely manner (and shall indemnify and hold harmless Gatherer from against any Losses, including any expenses incurred by Gatherer in acquiring such allowances in the marketplace, arising out of Shipper's failure to so provide such allowances) and (ii) Shipper shall be fully responsible for such Emissions Charges and shall reimburse Gatherer for any Emissions Charges paid by Gatherer within ten (10) Days of receipt of Gatherer's invoice.

ARTICLE 11
MEASUREMENT EQUIPMENT AND PROCEDURES

Section 11.1 Equipment. Gatherer shall install, own, operate, and maintain Measurement Facilities to measure Production at all the System Receipt Points and shall ensure that the relevant Downstream Pipeline or Processing Plant installs, owns, operates, and maintains Measurement Facilities at the System Delivery Points (but downstream of any slug catcher) for Gas. Measurement Facilities owned by Gatherer at the Receipt Points shall meet current industry standards for custody transfer measurement. For Gas measurement, unless the Parties agree otherwise, with respect to all Well Pads initially connected after September 1, 2017, Gatherer shall install Measurement Facilities with a single orifice meter for each Well Pad, and Shipper shall install, own, and operate flow lines from the Wells on each such Well Pad to such

Measurement Facilities. Shipper shall have the right to install check Measurement Facilities at each Receipt Point, including the right to install check measurement equipment on Gatherer's meter tubes and orifice unions.

Section 11.2 Gas Measurement Standards. The following standards shall apply to the measurement of Gas hereunder:

(a) Where measurement is by orifice meter, all fundamental constants, observations, records, and procedures involved in the determination and/or verification of the quantity and other characteristics of the Gas delivered hereunder shall be in accordance with the standards prescribed in the latest edition of A.G.A. Report No. 3 (ANSI/API 2530) "Orifice Metering of Natural Gas" with any revisions, amendments or supplements as may be mutually acceptable to the Parties.

(b) Where measurement is by ultrasonic meter, all fundamental constants, observations, records, and procedures involved in the determination and/or verification of the quantity and other characteristics of the Gas delivered hereunder shall be in accordance with the standards prescribed in the latest edition of A.G.A. Report No. 9 "Measurement of Gas by Multi Path Ultrasonic Meters" with any revisions, amendments or supplements as may be mutually acceptable to the Parties.

(c) The changing and integration of the charts (if utilized for measurement purposes hereunder) and calibrating and adjusting of meters shall be performed by Gatherer.

Section 11.3 Liquid Hydrocarbons Measurement Standards. The following standards shall apply to the measurement of Liquid Hydrocarbons hereunder:

(a) Measurement Devices used in the measurement of Liquid Hydrocarbons shall be designed, installed, and operated in accordance with specifications of the American Petroleum Institute Manual of Petroleum Measurement Standards or other applicable industry standards, as amended from time to time.

(b) The quality and gravity of Liquid Hydrocarbons shall be determined from laboratory analyses of representative samples following the calculation procedures in American Petroleum Institute Manual of Petroleum Measurement Standards or other applicable industry standards

Section 11.4 Gas Measurement.

(a) The unit of volume for measurement of Gas delivered hereunder shall be one Mcf at a base temperature of 60 degrees Fahrenheit and at an absolute pressure of 14.73 psia and without adjustment for water vapor content. It is agreed that for the purposes of measurement and computations hereunder, (a) the atmospheric pressure shall be based on the atmospheric pressure determined and used by Downstream Pipelines at the Delivery Point(s) regardless of the atmospheric pressure at which the Gas is measured and (b) all measurements and testing performed hereunder shall all be made by Gatherer in accordance with applicable rules, regulations, and orders.

(b) Gatherer's Measurement Facilities at the System Receipt Points shall be spot samplers, continuous samplers, or gas chromatographs, as Gatherer shall in its discretion determine, subject to the minimum requirements set forth in the following three sentences. Gatherer shall at least take monthly spot samples at all Measurement Facilities located at System Receipt Points where Gas is received into the Gathering System from a single Well. At all Measurement Facilities located at System Receipt Points where Gas is received into the System from more than one Well, Gatherer shall at least (i) take monthly spot samples if such Measurement Facilities measure less than five thousand (5,000) Mcf per Day, (ii) use continuous samplers if such Measurement Facilities measure from five thousand (5,000) to twenty thousand (20,000) Mcf per Day, and (iii) use gas chromatographs if such Measurement Facilities measure more than twenty thousand (20,000) Mcf per Day. Measurement at the System Delivery Points shall be done using continuous samplers (for Measurement Facilities metering less than twenty thousand (20,000) Mcf per Day) and online gas chromatographs (for Measurement Facilities metering twenty thousand (20,000) Mcf or more per Day). Gatherer shall procure or cause to be procured a sample of Gas at each System Delivery Point and analyze the samples by chromatographic analysis to determine the component content (mole percent), specific gravity, and the Thermal Content thereof. These determinations shall be made utilizing the following standards: (i) Gas Processors Association Obtaining Natural Gas Samples for Analysis by Gas, Publication No. 2166 as amended or supplemented from time to time and (ii) Gas Processors Association Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Publication No. 2161 as amended or supplemented from time to time, or (iii) any other tests that are mutually agreed by Shipper and Gatherer.

(c) The specific gravity of Gas shall be measured by a standard gravity balance in accordance with the provisions of the Natural Gas Processors Association Publication No. 3130, entitled "Standard Method for Determining the Specific Gravity of Gas", or by a gravitometer employing the "Momentum Method" as described in Chapter VII, "Determination of Specific Gravity", of the American Gas Association Gas Measurement Manual, 1963, in each case, as such may be amended from time to time. The specific gravity will be determined and calculated to the nearest one-thousandth (0.001).

(d) The temperature of Gas shall be determined by means of a recording thermometer recording the temperature of such Gas flowing through each measurement meter. The average temperature to the nearest one degree (1º) Fahrenheit, obtained while Gas is being delivered, will be the applicable flowing Gas temperature for the period under consideration.

(e) The deviation of the Gas from Ideal Gas Laws shall be determined in accordance with the A.G.A. Par Research Project NX-19 Report "Manual for the Determination of Supercompressibilty Factors for Natural Gas", Reprinted 1976, if the composition of the Gas is such to render this procedure applicable.

(f) Physical constants required for making calculations hereunder shall be taken from the Gas Processors Association Table of Physical Properties for Hydrocarbons and Other Compounds of Interest to the Natural Gas Industry, Publication No. 2145 as amended or supplemented from time to time. Physical constants for the hexanes and heavier hydrocarbons portion of hydrocarbon mixtures shall be assumed to be the same as the physical constants for hexane.

Section 11.5 Notice of Measurement Facilities Inspection and Calibration. Each Party shall give reasonable notice to the other Party in order that the other Party may, at its option, have representatives present to observe any reading, inspecting, testing, calibrating or adjusting of Measurement Facilities used in measuring or checking the measurement of receipts or deliveries of Production under this Agreement. Any Measurement Facilities equipment found to be registering inaccurately shall be promptly adjusted to register as accurately as possible or repaired or replaced, as necessary for accurate measurement. The official electronic data from such Measurement Facilities shall remain the property of the Measurement Facilities' owner, but copies of such records shall, upon written request, be submitted, together with calculations and flow computer configurations therefrom, to the requesting Party for inspection and verification.

Section 11.6 Measurement Accuracy Verification.

(a) Each Party shall verify the accuracy of all Measurement Facilities owned by such Party at intervals based upon the following schedule:

(i) semi-annually for Gas Measurement Facilities metering less than one thousand (1,000) Mcf per Day;

(ii) quarterly for Gas Measurement Facilities metering between one thousand (1,000) and five thousand (5,000) Mcf per Day;

(iii) monthly for Gas Measurement Facilities metering more than five thousand (5,000) Mcf per Day; and

(iv) quarterly for Liquid Hydrocarbons Measurement Facilities.

Neither Party shall be required to cause adjustment or calibration of such equipment more frequently than once per Month, unless a special test is requested pursuant to Section 11.7.

(b) If, during any test of the Measuring Facilities, an adjustment or calibration error is found which results in an incremental adjustment to the calculated flow rate through each meter run in excess of one percent (1%) of the adjusted flow rate (whether positive or negative and using the adjusted flow rate as the percent error equation denominator), then any previous recordings of such equipment shall be corrected to zero error for any period during which the error existed (and which is either known definitely or agreed to by the Parties) and the total flow for the period redetermined in accordance with the provisions of Section 11.8. If the period of error condition cannot be determined or agreed upon between the Parties, such correction shall be made over a period extending over the last one half of the time elapsed since the date of the prior test revealing the one percent (1%) error.

(c) If, during any test of any Measurement Facilities, an adjustment or calibration error is found which results in an incremental adjustment to the calculated hourly flow rate which does not exceed one percent (1%) of the adjusted flow rate, all prior recordings and electronic flow computer data shall be considered to be accurate for quantity determination purpose.

Section 11.7 Special Tests. In the event a Party desires a special test (a test not scheduled by a Party under the provisions of Section 11.6) of any Measurement Facilities, seventy-two (72) hours advance notice shall be given to the other Party and both Parties shall cooperate to secure a prompt test of the accuracy of such equipment. If the Measurement Facilities tested are found to be within the range of accuracy set forth in Section 11.6(b), then the Party that requested the test shall pay the costs of such special test including any labor and transportation costs pertaining thereto. If the Measurement Facilities tested are found to be outside the range of accuracy set forth in Section 11.6(b), then the Party that owns such Measurement Facilities shall pay such costs and perform the corrections according to Section 11.8.

Section 11.8 Metered Flow Rates in Error. If, for any reason, any Measurement Facilities are (i) out of adjustment, (ii) out of service, or (iii) out of repair and the total calculated flow rate through each meter run is found to be in error by an amount of the magnitude described in Section 11.6, the total quantity of Production delivered shall be determined in accordance with the first of the following methods which is feasible:

(a) By using the registration of any mutually agreeable check metering facility, if installed and accurately registering (subject to testing as provided for in Section 11.6);

(b) Where multiple meter runs exist in series, by calculation using the registration of such meter run equipment; provided that they are measuring Production from upstream and downstream headers in common with the faulty metering equipment, are not controlled by separate regulators, and are accurately registering;

(c) By correcting the error by re-reading of the official charts, or by straightforward application of a correcting factor to the quantities recorded for the period (if the net percentage of error is ascertainable by calibration, tests or mathematical calculation); or

(d) By estimating the quantity, based upon deliveries made during periods of similar conditions when the meter was registering accurately.

Section 11.9 Record Retention. The Party owning the Measurement Facilities shall retain and preserve all test data, charts, and similar records for any calendar year for a period of at least twenty-four (24) Months following the end of such calendar year unless applicable law or regulation requires a longer time period or the Party has received written notification of a dispute involving such records, in which case records shall be retained until the related issue is resolved.

Section 11.10 Access.

(a) Gatherer shall contract with eLynx Technologies or a provider of comparable services reasonably satisfactory to Shipper (the "***Monitoring Services Provider***") for remote monitoring of Gas Measurement Facilities, including monitoring of measurement data on an hourly (or more frequent) basis for flow rate, meter pressures, meter temperature, orifice diameter, Gross Heating Value, and composition for importation into PRAMS Plus production software or comparable production software ("***Remote Monitoring Data***").

(b) Gatherer shall (i) provide the Monitoring Services Provider access to all of Gatherer's radio and telephone infrastructure to access and gather all Remote Monitoring Data and (ii) cause the Monitoring Services Provider to allow Shipper to view and access all Remote Monitoring Data on the Monitoring Service Provider's system, including the ability to poll for Remote Monitoring Data through the Monitoring Services Provider's system.

(c) Gatherer shall provide Shipper 120 Days' notice of any termination by Gatherer of its contract with any Monitoring Services Provider.

ARTICLE 12
NOTICES

Section 12.1 Notices. Unless otherwise provided herein, any notice, request, invoice, statement, or demand which either Party desires to serve upon the other regarding this Agreement shall be made in writing and shall be considered as delivered (i) when hand delivered, or (ii) when delivery is confirmed by pre-paid delivery service (such as FedEx, UPS, DHL or a similar delivery service), or (iii) if mailed by United States certified mail, postage prepaid, three (3) Business Days after mailing, or (iv) if sent by facsimile transmission, when receipt is confirmed by the equipment of the transmitting Party, or (v) when sent via email; provided, if sent by email after normal business hours or if receipt of a facsimile transmission is confirmed after normal business hours, receipt shall be deemed to be the next Business Day. Notwithstanding the foregoing, if a Party desires to serve upon the other a notice of default under this Agreement, or if Shipper desires to serve upon Gatherer a Connection Notice, the delivery of such notice shall be considered effective under this Section 12.1 only if delivered by any method set forth in items (i) through (iv) above. Any notice shall be given to the other Party at the following address, or to such other address as either Party shall designate by written notice to the other:

Shipper: ANTERO RESOURCES CORPORATION
1615 Wynkoop Street
Denver, Colorado 80202

Attn: Chief Financial Officer
Phone: (303) 357-7310
Fax Number: (303) 357-7315

With copy to: For gas control, nominations & balancing:
Manager of Gas Marketing
Phone: (303) 357-7310
Fax Number: (303) 357-7315

For accounting, financial, and legal:
Controller
Phone: (303) 357-7310
Fax Number: (303) 357-7315

Gatherer: ANTERO MIDSTREAM LLC
1615 Wynkoop
Denver, Colorado 80202

Attn: Chief Financial Officer
Phone: (303) 357-7310
Fax Number: (303) 357-7315

For gas control, nominations & balancing:
Manager of Gas Marketing
Phone: (303) 357-7310
Fax Number: (303) 357-7315

For accounting, financial, and legal:
Controller
Phone: (303) 357-7310
Fax Number: (303) 357-7315

ARTICLE 13
PAYMENTS

Section 13.1 Invoices. Not later than the tenth (10th) Day following the end of each Month, Gatherer shall provide Shipper with a detailed statement setting forth the volume and Thermal Content of Gas and, if applicable, the volume of Liquid Hydrocarbons received by Gatherer at the Receipt Points in such Month, the volume and Thermal Content of Delivery Point Gas allocated to Shipper and, if applicable, the volume of Liquid Hydrocarbons redelivered to Shipper in such Month, the quantity of Gas and the cost of electricity used as Fuel allocated to Shipper in such Month, the volume and Thermal Content of Lost and Unaccounted For Gas for such Month, and the Gathering Fee, the High Pressure Gathering Fee, the Compression Fee, the Liquids Gathering Fee, and the Cost of Service Fee with respect to such Month, together with measurement summaries and the amount of any Imbalances and all relevant supporting documentation, to the extent available on such tenth (10th) Day (with Gatherer being obligated to deliver any such supporting documentation that is not available on such tenth (10th) Day as soon as it becomes available). Each invoice delivered at the end of each calendar quarter applicable to time periods between January 1, 2020 and December 31, 2023 shall include the calculation of the Fee Rebate (if any) for the applicable calendar quarter, and apply such Fee Rebate (if any) as a credit against the Gathering Fees as described in Section 5.2(a). Shipper shall make payment to Gatherer by the last Business Day of the Month in which such invoice is received. Such payment shall be made by wire transfer pursuant to wire transfer instructions delivered by Gatherer to Shipper in writing from time to time. If any overcharge or undercharge in any form whatsoever shall at any time be found and the invoice therefor has been paid, Gatherer shall refund any amount of overcharge, and Shipper shall pay any amount of undercharge, within thirty (30) Days after final determination thereof, provided, however, that no retroactive adjustment will be made beyond a period of twenty-four (24) Months from the date of a statement hereunder.

Section 13.2 Right to Suspend on Failure to Pay. If any undisputed amount due hereunder remains unpaid for sixty (60) Days after the due date, Gatherer shall have the right to suspend or discontinue Services hereunder until any such past due amount is paid.

Section 13.3 Audit Rights. Either Party, on not less than thirty (30) Days prior written notice to the other Party, shall have the right at its expense, at reasonable times during normal business hours, but in no event more than twice in any period of twelve (12) consecutive Months, to audit the books and records of the other Party to the extent necessary to verify the accuracy of any statement, allocation, measurement, computation, charge, payment made under, or obligation or right pursuant to this Agreement. The scope of any audit shall be limited to transactions affecting Dedicated Production and Delivery Point Gas hereunder and shall be limited to the twenty-four (24) Month period immediately prior to the Month in which the notice requesting an audit was given. All statements, allocations, measurements, computations, charges, or payments made in any period prior to the twenty-four (24) Month period immediately prior to the Month in which the audit is requested shall be conclusively deemed true and correct and shall be final for all purposes.

Section 13.4 Payment Disputes. In the event of any dispute with respect to any payment hereunder, Shipper shall make timely payment of all undisputed amounts, and Gatherer and Shipper will use good faith efforts to resolve the disputed amounts within sixty (60) Days following the original due date. Any amounts subsequently resolved shall be due and payable within ten (10) Days of such resolution.

Section 13.5 Interest on Late Payments. In the event that Shipper shall fail to make timely payment of any sums, except those contested in good faith or those in a good faith dispute, when due under this Agreement, interest will accrue at an annual rate equal to ten percent (10%) from the date payment is due until the date payment is made.

Section 13.6 Credit Assurance. Gatherer shall apply consistent evaluation practices to all similarly situated shippers to determine the new Shipper's financial ability to perform its payment obligations under this Agreement.

(a) If Gatherer has reasonable grounds for insecurity regarding the performance of any obligation by Shipper under this Agreement (whether or not then due), Gatherer may demand Adequate Assurance of Performance from Shipper, which Adequate Assurance of Performance shall be provided to Gatherer within five (5) Days after written request. If Shipper fails to provide such Adequate Assurance of Performance within such time, then Gatherer may suspend its performance under this Agreement until such Adequate Assurance of Performance is provided. However, any action by Gatherer shall not relieve Shipper of its payment obligations. The exercise by Gatherer of any right under this Section 13.6 shall be without prejudice to any claims for damages or any other right under this Agreement. As used herein, "***Adequate Assurance of Performance***" means any of the following, in Gatherer's reasonable discretion:

(i) an irrevocable standby letter of credit in an amount not to exceed an amount that is equal to sixty (60) Days of Shipper's payment obligations hereunder from a financial institution rated at least A- by S&P or at least A3 by Moody's in a form and substance satisfactory to Gatherer;

(ii) cash collateral in an amount not to exceed an amount that is equal to sixty (60) Days of Shipper's payment obligations hereunder to be deposited in an escrow account as designated by Gatherer; Gatherer is hereby granted a security interest in and right of set-off against all cash collateral, which is or may hereafter be delivered or otherwise transferred to such escrow account in connection with this Agreement; or

(iii) a guaranty in an amount not to exceed an amount that is equal to sixty (60) Days of Shipper's payment obligations hereunder reasonably acceptable to Gatherer.

(b) The term of any security provided under this Section 13.6 shall be as reasonably determined by Gatherer, but it shall never exceed sixty (60) Days, after which the security shall terminate (or in the case of cash collateral, be immediately returned by Gatherer to Shipper without further action by either Party). Nothing shall prohibit Gatherer, however, from requesting additional Adequate Assurance of Performance following the end of any such term, so long as the conditions triggering such a request under this Section 13.6 exist.

(c) Should Shipper fail to provide Adequate Assurance of Performance within five (5) Days after receipt of written demand for such assurance (which shall include reasonable particulars for the demand and documentation supporting the calculation of such amount demanded), then Gatherer shall have the right (notwithstanding any other provision of this Agreement) to suspend performance under this Agreement until such time as Shipper furnishes Adequate Assurance of Performance.

Section 13.7 Excused Performance. Gatherer will not be required to perform or continue to perform services hereunder, and Shipper shall not be obligated to deliver Dedicated Production to the Gathering System (or make any payments required under Section 5.1(d)(i) and Section 5.1(d)(ii)) in the event:

(a) the other Party has voluntarily filed for bankruptcy protection under any chapter of the United States Bankruptcy Code;

(b) the other Party is the subject of an involuntary petition of bankruptcy under any chapter of the United States Bankruptcy Code, and such involuntary petition has not been settled or otherwise dismissed within ninety (90) Days of such filing; or

(c) the other Party otherwise becomes insolvent, whether by an inability to meet its debts as they come due in the ordinary course of business or because its liabilities exceed its assets on a balance sheet test; and/or however such insolvency may otherwise be evidenced.

ARTICLE 14
FORCE MAJEURE

Section 14.1 Suspension of Obligations. In the event a Party is rendered unable, wholly or in part, by Force Majeure to carry out its obligations under this Agreement, other than the obligation to make payments then or thereafter due hereunder, and such Party promptly gives notice and reasonably full particulars of such Force Majeure in writing to the other Party promptly after the occurrence of the cause relied on, then the obligations of the Party giving such notice, so far as and to the extent that they are affected by such Force Majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as reasonably possible be remedied with all reasonable dispatch by the Party claiming Force Majeure.

Section 14.2 Definition of Force Majeure. The term "***Force Majeure***" as used in this Agreement shall mean any cause or causes not reasonably within the control of the Party claiming suspension and which, by the exercise of reasonable diligence, such Party is unable to prevent or overcome, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, acts of terror, sabotage, wars, blockades, military action, insurrections, riots, epidemics, landslides, subsidence, lightning, earthquakes, fires, storms or storm warnings, crevasses, floods, washouts, civil disturbances, explosions, breakage or accident to wells, machinery, equipment or lines of pipe, the necessity for testing or making repairs or alterations to wells, machinery, equipment or lines of pipe, freezing of wells, equipment or lines of pipe, inability of any Party hereto to obtain, after the exercise of reasonable diligence, necessary materials, supplies, or government authorizations, any action or restraint by any Governmental Authority (so long as the Party claiming suspension has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such action or restraint, and as long as such action or restraint is not the result of a failure by the claiming Party to comply with applicable laws, rules, regulations, or orders), and, in the case of Gatherer as the claiming party, any breach of any representation or warranty of Shipper or any failure by Shipper to perform any obligation of Shipper under that certain Contribution Agreement dated November 10, 2014, by and between Shipper and Gatherer.

Section 14.3 Settlement of Strikes and Lockouts. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the Party having the difficulty, and that the above requirement that any Force Majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of the opposing party when such course is inadvisable in the sole discretion of the Party having the difficulty.

Section 14.4 Payments for Production Delivered. Notwithstanding the foregoing, it is specifically understood and agreed by the Parties that an event of Force Majeure will in no way affect or terminate Shipper's obligation to make payment for quantities of Production delivered prior to such event of Force Majeure.

ARTICLE 15
INDEMNIFICATION

Section 15.1 Gatherer. Subject to the terms of this Agreement, including Section 18.8, Gatherer shall release, indemnify, defend, and hold harmless Shipper and its Affiliates, directors, officers, employees, agents, consultants, representatives, and invitees from and against all claims and losses arising out of or relating to (i) the operations of Gatherer and (ii) any breach of this agreement by Gatherer.

Section 15.2 Shipper. Subject to the terms of this Agreement, including Section 18.8, Shipper shall release, indemnify, defend, and hold harmless Gatherer and its Affiliates, directors, officers, employees, agents, consultants, representatives, and invitees from and against all claims and losses arising out of or relating to (i) the operations of Shipper and (ii) any breach of this agreement by Shipper.

ARTICLE 16
CUSTODY AND TITLE

Section 16.1 Custody. As among the Parties, Shipper shall be in custody, control and possession of (i) Shipper's Production hereunder until such Production is delivered to the Receipt Points and (ii) the Delivery Point Gas and Liquid Hydrocarbons after they are delivered to Shipper at the Delivery Points, including any portion of any Delivery Point Gas which accumulates as liquids. As among the Parties, Gatherer shall be in custody, control and possession of all Production in the Gathering System at all other times, including any portion thereof which accumulates as liquids. The Party having custody and control of Production under the terms of this Agreement shall be responsible for, and shall defend, indemnify, release and hold the other Party and its Affiliates, directors, officers, employees, agents, consultants, representatives, and invitees harmless from and against, all claims and losses of whatever kind and nature for anything that may happen or arise with respect to such Production when such Production is in its custody and control, including losses resulting from any negligent acts or omissions of any indemnified party, but excluding any losses to the extent caused by or arising out of the negligence, gross negligence, or willful misconduct of the indemnified party.

Section 16.2 Shipper Warranty. Shipper represents and warrants that it owns, or has the right to deliver to the Gathering System, all Production delivered under this Agreement, free and clear of all liens, encumbrances and adverse claims. If the title to Production delivered by Shipper hereunder is disputed or is involved in any legal action, Gatherer shall have the right to cease receiving such Production, to the extent of the interest disputed or involved in legal action, during the pendency of the action or until title is freed from the dispute, or until Shipper furnishes, or causes to be furnished, indemnification to save Gatherer harmless from all claims arising out of the dispute or action, with surety acceptable to Gatherer. Shipper hereby indemnifies Gatherer against and holds Gatherer harmless from any and all claims and losses arising out of or related to any breach of the foregoing representation and warranty.

Section 16.3 Title. Title to all Production delivered under this Agreement, including all constituents thereof, shall remain with and in Shipper or its customers at all times; provided, however, title to Production used as Fuel and Lost and Unaccounted For Gas shall pass from

Shipper or its customer to Gatherer immediately downstream of the Receipt Point. Title to Condensate that is recovered from Shipper's Gas in the Gathering System shall remain with Shipper. Title to water (i) that is removed from Shipper's Gas in Gatherer's dehydration facilities shall pass to Gatherer immediately downstream of the point of recovery, and (ii) that condenses from Shipper's Gas in the Gathering System shall pass to Gatherer immediately downstream of the Receipt Point.

ARTICLE 17
TAXES; ROYALTIES

Section 17.1 Taxes. Shipper shall pay or cause to be paid and agrees to hold Gatherer harmless as to the payment of all excise, gross production, severance, sales, occupation and all other Taxes, charges or impositions of every kind and character required by statute or by order of Governmental Authorities and levied against or with respect to Shipper's Production, Delivery Point Gas or the Services provided under this Agreement. Gatherer shall not become liable for such Taxes, unless designated to remit those Taxes on behalf of Shipper by any duly constituted jurisdictional agency having authority to impose such obligations on Gatherer, in which event the amount of such Taxes remitted on Shipper's behalf shall be (i) reimbursed by Shipper upon receipt of invoice, with corresponding documentation from Gatherer setting forth such payments, or (ii) deducted from amounts otherwise due Gatherer under this Agreement. Gatherer shall pay or cause to be paid all Taxes, charges and assessments of every kind and character required by statute or by order of Governmental Authorities with respect to the Gathering System. Except as provided in Exhibit I attached hereto, neither Party shall be responsible nor liable for any Taxes or other statutory charges levied or assessed against the facilities of the other Party, including ad valorem tax (however assessed), used for the purpose of carrying out the provisions of this Agreement or against the net worth or capital stock of such Party.

Section 17.2 Royalties. As between the Parties, Shipper shall have the sole and exclusive obligation and liability for the payment of all Persons due any proceeds derived from Shipper's Production or Delivery Point Gas (including all constituents and products thereof) delivered under this Agreement, including royalties, overriding royalties, and similar interests, in accordance with the provisions of the leases or agreements creating those rights to proceeds. In no event will Gatherer have any obligation to those Persons due any of those proceeds of production attributable to any such Production (including all constituents and products thereof) delivered under this Agreement. Although Shipper shall retain title to Production as provided in this Section 16.3, Gatherer shall have the right to commingle Production delivered by Shipper with Third Party Production.

ARTICLE 18
MISCELLANEOUS

Section 18.1 Rights. The failure of either Party to exercise any right granted hereunder shall not impair nor be deemed a waiver of that Party's privilege of exercising that right at any subsequent time or times.

Section 18.2 Applicable Laws. This Agreement is subject to all valid present and future laws, regulations, rules and orders of Governmental Authorities now or hereafter having jurisdiction over the Parties, this Agreement, or the services performed or the facilities utilized under this Agreement. The Parties hereby agree that, in the event that (i) Gatherer's facilities, or any part thereof, become subject to regulation by the Federal Energy Regulatory Commission, or any successor agency thereto ("***FERC***"), or any other Governmental Authority of the rates, terms and conditions for service, (ii) Gatherer becomes obligated by FERC or any other Governmental Authority to provide Services or any portion thereof on an open access, nondiscriminatory basis as a result of Gatherer's execution, performance or continued performance of this Agreement or (iii) FERC or any other Governmental Authority seeks to modify any rates under, or terms or conditions of, this Agreement, then:

(a) to the maximum extent permitted by law, it is the intent of the Parties that the rates and terms and conditions established by the FERC Governmental Authority having jurisdiction shall not alter the rates or terms and conditions set forth in this Agreement, and the Parties agree to vigorously defend and support in good faith the enforceability of the rates and terms and conditions of this Agreement;

(b) in the event that FERC or the Governmental Authority having jurisdiction modifies the rates or terms and conditions set forth in this Agreement, the Parties hereby agree to negotiate in good faith to enter into such amendments to this Agreement and/or a separate arrangement in order to give effect, to the greatest extent possible, to the rates and other terms and conditions set forth herein; and

(c) in the event that the Parties are not successful in accomplishing the objectives set forth in (a) or (b) above such that the Parties are in substantially the same economic position as they were prior to any such regulation, then either Party may terminate this Agreement upon the delivery of written notice of termination to the other Party.

Section 18.3 Governing Law; Jurisdiction.

(a) This Agreement shall be governed by, construed, and enforced in accordance with the laws of the State of Colorado without regard to choice of law principles.

(b) The Parties agree that the appropriate, exclusive and convenient forum for any disputes between the Parties arising out of this Agreement or the transactions contemplated hereby shall be in any state or federal court in City and County of Denver, Colorado, and each of the Parties irrevocably submits to the jurisdiction of such courts solely in respect of any proceeding arising out of or related to this Agreement. The Parties further agree that the Parties shall not bring suit with respect to any disputes arising out of this Agreement or the transactions contemplated hereby in any court or jurisdiction other than the above specified courts.

Section 18.4 Successors and Assigns.

(a) This Agreement shall extend to and inure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns. Except as set forth in Section 18.4(b) and Section 18.4(c), neither Party shall have the right to assign its respective rights and obligations in whole or in part under this Agreement without the prior written consent of the other Party (which such consent shall not be unreasonably withheld, conditioned or delayed), and any assignment or attempted assignment made otherwise than in accordance with this Section 18.4 shall be null and void *ab initio*.

(b) Notwithstanding the foregoing clause (a), Gatherer may perform all services under this Agreement itself using its own gathering, compression, and other facilities and/or perform any or all such services through third parties, in which case references herein to the Gathering System shall be deemed to be references to such facilities of the relevant third party.

(c) Notwithstanding the foregoing clause (a):

(i) Gatherer shall have the right to assign its rights under this Agreement, in whole or in part, as applicable, without the consent of Shipper if such assignment is made to any Person to which the Gathering System or any part thereof has been or will be transferred that assumes in writing all of Gatherer's obligations hereunder (if applicable, to the extent that part of the Gathering System being transferred to such Person) and is (A) an Affiliate of Gatherer or (B) a Person to which the Gathering System has been or will be transferred who (1) hires (or retains, as applicable) operating personnel who are then operating the Gathering System (or has similarly experienced operating personnel itself), (2) has operated for at least two (2) years prior to such assignment systems similar to the Gathering System, or (3) contracts for the operation of the Gathering System with another Person that satisfies either of the foregoing conditions (1) or (2) in this clause (B), provided in the case of an assignment pursuant to this clause (B), the assignee has creditworthiness as reasonably determined by Shipper that is equal to the higher of Gatherer's creditworthiness as of the Original Agreement Effective Date and Gatherer's creditworthiness as of the date of the assignment.

(ii) Gatherer shall have the right to grant a security interest in this Agreement to a lender or other debt provider (or trustee or agent on behalf of such lender) of Gatherer.

(iii) Shipper shall have the right to assign its rights under this Agreement, in whole or in part, as applicable, without the consent of Gatherer, to any Person to which it sells, assigns, or otherwise transfers all or any portion of the Dedicated Properties and (A) who assumes in writing all of Shipper's obligations hereunder (if applicable, to the extent of the Dedicated Properties being transferred to such Person) and (B) whose credit rating is equal to or greater than the greater of Shipper's credit rating as of the Original Agreement Effective Date and Shipper's credit rating as of the date of the assignment.

(d) Upon an assignment by Gatherer in accordance with Section 18.4(c)(i)(B) Gatherer shall be released from its obligations under this Agreement to the extent of such assignment. Upon an assignment by Shipper in accordance with Section 18.4(c)(ii), Shipper shall be released from its obligations under this Agreement to the extent of such assignment.

Section 18.5 Severability. If any provision of this Agreement is determined to be void or unenforceable, in whole or in part, then (i) such provision shall be deemed inoperative to the extent it is deemed void or unenforceable, (ii) the Parties agree to enter into such amendments to this Agreement in order to give effect, to the greatest extent legally possible, to the provision that is determined to be void or unenforceable and (iii) the other provisions of this Agreement in all other respects shall remain in full force and effect and binding and enforceable to the maximum extent permitted by law; provided, however, that in the event that a material term under this Agreement is so modified, the Parties will, timely and in good faith, negotiate to revise and amend this Agreement in a manner which preserves, as closely as possible, each Party's business and economic objectives as expressed by the Agreement prior to such modification.

Section 18.6 Confidentiality.

(a) Confidentiality. Except as otherwise provided in this Section 18.6, each Party agrees that it shall maintain all terms and conditions of this Agreement, and all information disclosed to it by the other Party or obtained by it in the performance of this Agreement and relating to the other Party's business (including Development Plans, Gathering System Plans, and all data relating to the production of Shipper, including well data, production volumes, volumes gathered, transported, or compressed, and gas quality) (collectively, "***Confidential Information***") in strictest confidence, and that it shall not cause or permit disclosure of this Agreement or its existence or any provisions contained herein without the express written consent of the other Party.

(b) Permitted Disclosures. Notwithstanding Section 18.6(a) disclosures of any Confidential Information may be made by either Party (i) to the extent necessary for such Party to enforce its rights hereunder against the other Party; (ii) to the extent to which a Party is required to disclose all or part of this Agreement by a statute or by the order or rule of a Governmental Authority exercising jurisdiction over the subject matter hereof, by order, by regulations, or by other compulsory process (including deposition, subpoena, interrogatory, or request for production of documents); (iii) to the extent required by the applicable regulations of a securities or commodities exchange; (iv) to a third person in connection with a proposed sale or other transfer of a Party's interest in this Agreement, provided such third person agrees in writing to be bound by the terms of this Section 18.6; (v) to its own directors, officers, employees, agents and representatives; (vi) to an Affiliate; (vii) to financial advisors, attorneys, and banks, provided that such Persons are subject to a confidentiality undertaking consistent with this Section 18.6(b), or (viii) except for information disclosed pursuant to Article 3 of this Agreement, to a royalty, overriding royalty, net profits or similar owner burdening Dedicated Production, provided such royalty, overriding royalty, net profits or similar owner, agrees in writing to be bound by the terms of this Section 18.6.

(c) Notification. If either Party is or becomes aware of a fact, obligation, or circumstance that has resulted or may result in a disclosure of any of the terms and conditions of this Agreement authorized by Section 18.6(b)(ii) or (iii), it shall so notify in writing the other Party promptly and shall provide documentation or an explanation of such disclosure as soon as it is available.

(d) Party Responsibility. Each Party shall be deemed solely responsible and liable for the actions of its directors, officers, employees, agents, representatives and Affiliates for maintaining the confidentiality commitments of this Section 18.6.

(e) Public Announcements. The Parties agree that prior to making any public announcement or statement with respect to this Agreement or the transaction represented herein permitted under this Section 18.6, the Party desiring to make such public announcement or statement shall provide the other Party with a copy of the proposed announcement or statement prior to the intended release date of such announcement. The other Party shall thereafter consult with the Party desiring to make the release, and the Parties shall exercise their reasonable best efforts to (i) agree upon the text of a joint public announcement or statement to be made by both such Parties or (ii) in the case of a statement to be made solely by one Party, obtain approval of the other Party to the text of a public announcement or statement. Nothing contained in this Section 18.6 shall be construed to require either Party to obtain approval of the other Party to disclose information with respect to this Agreement or the transaction represented herein to any Governmental Authority to the extent required by applicable law or necessary to comply with disclosure requirements of the Securities and Exchange Commission, New York Stock Exchange, or any other regulated stock exchange.

(f) Survival. The provisions of this Section 18.6 shall survive any expiration or termination of this Agreement; provided that other than with respect to information disclosed pursuant to Article 3, as to which such provisions shall survive indefinitely, such provisions shall survive only a period of one (1) year.

Section 18.7 Entire Agreement, Amendments and Waiver; Amendment and Restatement of First A&R Agreement.

(a) This Agreement, including all exhibits hereto, integrates the entire understanding between the Parties with respect to the subject matter covered and supersedes all prior understandings, drafts, discussions, or statements, whether oral or in writing, expressed or implied, dealing with the same subject matter. This Agreement may not be amended or modified in any manner except by a written document signed by the Parties that expressly amends this Agreement. No waiver by either Party of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision hereof (whether or not similar), nor shall such waiver constitute a continuing waiver unless expressly provided. No waiver shall be effective unless made in writing and signed by the Party to be charged with such waiver.

(b) This Agreement amends, restates and supersedes the First A&R Agreement in its entirety (but such amendment and restatement does not affect the rights and obligations of the Parties accruing under the First A&R Agreement prior to the Effective Date). Except as otherwise expressly provided, all references to the Original Agreement or the First

A&R Agreement in any document, instrument, agreement or writing delivered pursuant to this Agreement shall hereafter be deemed to refer to this Agreement.

Section 18.8 Limitation of Liability. **NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, INDIRECT, CONSEQUENTIAL, PUNITIVE OR EXEMPLARY DAMAGES SUFFERED BY SUCH PARTY RESULTING FROM OR ARISING OUT OF THIS AGREEMENT OR THE BREACH THEREOF OR UNDER ANY OTHER THEORY OF LIABILITY, WHETHER TORT, NEGLIGENCE, STRICT LIABILITY, BREACH OF CONTRACT, WARRANTY, INDEMNITY OR OTHERWISE, INCLUDING LOSS OF USE, INCREASED COST OF OPERATIONS, LOSS OF PROFIT OR REVENUE, OR BUSINESS INTERRUPTIONS; PROVIDED, HOWEVER, THAT THE FOREGOING LIMITATION SHALL NOT APPLY TO ANY DAMAGE CLAIM ASSERTED BY OR AWARDED TO A THIRD PARTY FOR WHICH A PARTY WOULD OTHERWISE BE LIABLE UNDER ANY INDEMNIFICATION PROVISION SET FORTH HEREIN.**

Section 18.9 Headings. The headings and captions in this Agreement have been inserted for convenience of reference only and shall not define or limit any of the terms and provisions hereof.

Section 18.10 Rights and Remedies. Except as otherwise provided in this Agreement, each Party reserves to itself all rights, counterclaims, other remedies and defenses that such Party is or may be entitled to arising from or out of this Agreement or as otherwise provided by law.

Section 18.11 No Partnership. Nothing contained in this Agreement shall be construed to create an association, trust, partnership, or joint venture or impose a trust, fiduciary or partnership duty, obligation or liability on or with regard to either Party.

Section 18.12 Rules of Construction. In construing this Agreement, the following principles shall be followed:

(a) no consideration shall be given to the fact or presumption that one Party had a greater or lesser hand in drafting this Agreement;

(b) examples shall not be construed to limit, expressly or by implication, the matter they illustrate;

(c) the word “includes” and its syntactical variants mean “includes, but is not limited to,” “includes without limitation” and corresponding syntactical variant expressions;

(d) the plural shall be deemed to include the singular and vice versa, as applicable; and

(e) references to Section shall be references to Sections of this Agreement.

Section 18.13 No Third Party Beneficiaries. This Agreement is for the sole benefit of the Parties and their respective successors and permitted assigns, and shall not inure to the benefit of any other Person whomsoever or whatsoever, it being the intention of the Parties that no third Person shall be deemed a third party beneficiary of this Agreement.

Section 18.14 Further Assurances. Each Party shall take such acts and execute and deliver such documents as may be reasonably required to effectuate the purposes of this Agreement.

Section 18.15 Counterpart Execution. This Agreement may be executed in any number of counterparts, each of which shall be considered an original, and all of which shall be considered one and the same instrument.

Section 18.1 6 Memorandum of Agreement. Contemporaneously with the execution of this Agreement, the Parties shall execute, acknowledge, deliver and record a "short form" memorandum of this Agreement in the form of Exhibit J attached hereto (as modified, including by the addition of any required property descriptions, required by local law and practice to put such Memorandum of record and put third parties on notice of this Agreement), which shall be placed of record in each state and county in which the currently-existing Dedicated Properties are located. Further such memoranda shall be executed and delivered by Shipper as Gatherer from time to time requests to evidence the dedication of additional areas or Oil and Gas Interests under this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement on the date first set forth above.

ANTERO RESOURCES CORPORATION

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO MIDSTREAM LLC

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

EXHIBIT A

EXCLUDED WELLS

All gathering to Bluestone and ExCo vertical wells and all gathering to Davis Well and McKinley 1 & 2H Wells.

EXHIBIT B

DELIVERY POINTS

Low Pressure Delivery Points

West Virginia

1. Antero Mountain Compressor Station
2. Antero Pennington Compressor Station
3. Antero Monroe Compressor Station
4. Antero North Canton Compressor Station
5. Antero White Oak Compressor Station
6. Crestwood Appalachia Pipeline LLC (Crestwood) West Union Compressor Station
7. Crestwood Victoria Compressor Station

Ohio

1. EnLink Crum Compressor Station
2. EnLink Miller Compressor Station
3. EnLink Appalachian Compression, LLC, (EnLink) Upper Hill Compressor Station
4. EnLink Batesville Compressor Station
5. EnLink Reusser Compressor Station

High Pressure Delivery Points

West Virginia

Receipt Points	Delivery Points
Antero Mountain Compressor Station	MarkWest Sherwood Plant
Antero Monroe Compressor Station	Magnum Hunter or MarkWest Sherwood Plant

Antero North Canton Compressor Station	Summit Pike Fork lateral
Antero White Oak Compressor Station	MarkWest Sherwood Plant
Crestwood West Union Compressor Station	MarkWest Sherwood Plant
Crestwood Victoria Compressor Station	Summit Pike Fork lateral
Antero New Milton Compressor Station	MarkWest Sherwood Gas Processing Plant
Antero Midstream Pike Fork Compressor	Columbia Gas Transmission

Ohio

Receipt Points	**Delivery Points**
Antero Sanford well gathering line	Dominion East Ohio
EnLink Crum Compressor Station	MarkWest Seneca Plant
EnLink Miller Compressor Station	MarkWest Seneca Plant
EnLink Upper Hill Compressor Station	MarkWest Seneca Plant
EnLink Batesville Compressor Station	MarkWest Seneca Plant
EnLink Reusser Compressor Station	MarkWest Seneca Plant

Liquid Hydrocarbons Receipt and Delivery Points

Receipt Points	**Delivery Points**
Robert Pad, Ardith Pad, Miley Pad, Rich Pad, Wayne Pad, Myron Pad, Cynthia Pad, Smierciak Pad, Justice Pad	E2 Upper Hill Stabilizer
Roe Pad, Ervin Pad, J.R. Tyler Pad, Price Pad, Schultz Pad	E2 Batesville Station
Krupa Pad, Bond Pad, Roosen Pad, Bates Pad	E2Crum Stabilizer

EXHIBIT C

GATHERING SYSTEM

Any Low Pressure and High Pressure Gathering Systems gathering Gas from Shipper in the following counties and states:

Washington, PA;
Doddridge, WV;
Harrison, WV;
Tyler, WV;
Ritchie, WV;
Noble, OH;
Monroe, OH;
Guernsey, OH; and
Belmont, OH,
excluding facilities owned by Summit, Crestwood, ETC, M3, EQT, and MarkWest.

EXHIBIT D

INITIAL DEVELOPMENT PLAN

[attached]

EXHIBIT E

CONFLICTING DEDICATIONS

1. Second Amended and Restated Gas Gathering Agreement between Shipper and M3 Appalachia Gathering, LLC, dated July 1, 2013

2. Gathering and Compression Agreement between Shipper and Crestwood Marcellus Midstream LLC dated effective as of January 1, 2012.

3. Gas Gathering Agreement between Shipper and ETC Northeast Pipeline, LLC, dated January 1, 2010, as amended through the Effective Date.

EXHIBIT F

INITIAL GATHERING SYSTEM PLAN

[attached]

EXHIBIT G

FORM OF CONNECTION NOTICE

Antero Midstream LLC
1615 Wynkoop Street
Denver, Colorado 80202

Re: Second Amended and Restated Gathering and Compression Agreement dated December 8, 2019, between Antero Resources Corporation and Antero Midstream LLC (the "***Gathering Agreement***")

Ladies and Gentlemen:

This is a Connection Notice for purposes of the Gathering Agreement. Capitalized terms used but not defined in this Connection Notice have the meanings given such terms in the Gathering Agreement.

Gatherer is hereby notified that Shipper is planning to drill and complete the Planned Wells at the Planned Well Pads by the Target Completion Dates, in each case as set forth below:

Planned Well	**Planned Well Pad**	**Target Completion Date**

Very truly yours,

ANTERO RESOURCES CORPORATION

By: ______________________
Name: ______________________
Title: ______________________

EXHIBIT H

DEEMED CONNECTION NOTICES

[attached]

EXHIBIT I

COST OF SERVICE FEE

The Monthly Cost of Service Fee shall be calculated separately for each CS Facility for each Contract Year or, in the case of a CS Facility that is placed into service or acquired during a Contract Year, for the period from the first Day of the Month following the Month in which such CS Facility is placed into service or acquired through the end of such Contract Year, and for each Contract Year thereafter. The Cost of Service Fees for all CS Facilities for each Month shall be summed to result in the total Cost of Service Fee payable for such Month. The Monthly Cost of Service Fee for each Contract Year (or portion thereof, if applicable) for each CS Facility is determined as follows:

Monthly Capex Fee + Monthly O&M Fee = Monthly Cost of Service Fee.

The "***Monthly Capex Fee***" for each CS Facility is an amount equal to the product of (i) the amount that, if paid to Gatherer with respect to each Month remaining in the Recovery Term for such CS Facility, when taken together with all Prior Capex Fees paid to Gatherer for such CS Facility, would result in Gatherer recovering all of Gatherer's capital expenditures for such CS Facility (including the cost of acquisition of such CS Facility from Shipper, if applicable) over a period of 84 Months commencing with the placement in service or acquisition of such CS Facility (the "***Recovery Term***"), with a return on capital invested of 13% per annum. "***Prior Capex Fees***" means, with respect to any Contract Year and any CS Facility, the aggregate of the Monthly Capex Fees with respect to such CS Facility paid in all prior Contract Years. For purposes of determining the Monthly Capex Fee for any CS Facility, if such CS Facility is specified or sized to gather, compress, or otherwise handle volumes of Production in excess of those volumes of Dedicated Production projected in the Development Plan to be put through such CS Facility, only such portion of such capital expenditures that would be required to build facilities specified and sized to gather, compress, or otherwise the volumes of Dedicated Production projected in the Development Plan to be put through such CS Facility shall be considered.

The "***Monthly O&M Fee***" for any Contract Year (or portion thereof, if applicable) is an amount equal to:

(i) the sum of:

(a) the operations and maintenance costs and expenses, including the costs and expenses of repairs and replacements in kind, that Gatherer estimates it will incur with respect to the CS Facility during such Contract Year (or such portion thereof, if applicable); plus

(b) the O&M True Up Amount, if any,

(ii) divided by 12 (or by the number of Months in such portion of such Contract Year, if applicable).

The "***O&M True Up Amount***" means, with respect to any Contract Year (or portion thereof, if applicable) and any CS Facility,

(i) the positive or negative difference resulting from the following calculation:

(a) the actual operations and maintenance costs and expenses, including the costs and expenses of repairs and replacements in kind, incurred by Gatherer in the immediately prior Contract Year with respect to such CS Facility;

Minus

(b) the sum of the aggregate Monthly O&M Fees paid to Gatherer with respect to such CS Facility with respect to the immediately prior Contract Year,

(ii) plus 13% per annum.

The Monthly O&M Fee includes Gatherer's allocation to the CS Facility of Gatherer's overhead and general and administrative expenses together with Taxes payable by Gatherer with respect to the CS Facility or the Services performed in connection with the CS Facility (but excluding in any event Gatherer's income taxes), to the extent not otherwise paid or reimbursed by Shipper pursuant to this Agreement. For purposes of determining the Monthly O&M Fee for any CS Facility, if such CS Facility also used to gather, compress, or otherwise handle Third Party Production, only the portion of such operating expenses that are fairly allocable to gathering Dedicated Production shall be considered.

EXHIBIT J

MEMORANDUM OF AGREEMENT

THIS MEMORANDUM OF GATHERING AGREEMENT (this "Memorandum") is entered into effective [____________], 20[__], by and between **ANTERO RESOURCES CORPORATION** ("Shipper"), with an address of 1615 Wynkoop Street, Denver, Colorado 80202, and **ANTERO MIDSTREAM LLC,** with an address of 1615 Wynkoop Street, Denver, Colorado 80202 ("Gatherer").

WHEREAS, Shipper and Gatherer entered into that certain Second Amended and Restated Gathering and Compression Agreement effective December 8, 2019 (the "Agreement"), pursuant to which Gatherer will provide certain gathering and other services as therein set forth;

WHEREAS, any capitalized term used, but not defined, in this Memorandum shall have the meaning ascribed to such term in the Agreement; and

WHEREAS, the Parties desire to file this Memorandum of record in the real property records of [counties/states], to give notice of the existence of the Agreement and certain provisions contained therein;

NOW THEREFORE, FOR GOOD AND VALUABLE CONSIDERATION, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. Notice. Notice is hereby given of the existence of the Agreement and all of its terms, covenants and conditions to the same extent as if the Agreement was fully set forth herein. Certain provisions of the Agreement are summarized in Sections 2 through 3 below.

2. Dedication. Subject to the exceptions, exclusions, and reservations set forth in the Agreement and the other terms and conditions of the Agreement, (a) Shipper has exclusively dedicated and committed to deliver to Gatherer, as and when produced, all Production produced on or after the date of the Agreement that is attributable to the Oil and Gas Interests now owned or hereafter acquired by Shipper and located wholly or partly within the states of Pennsylvania, West Virginia, and Ohio, and certain other areas, or on lands pooled, unitized or communitized wholly or partly within any portion of the Dedication Area (the "Dedicated Properties"), together with all Production attributable to third parties that is produced from a Well located on the Dedicated Properties, which Production Shipper has the right to control and deliver for gathering ("Dedicated Production"), for gathering through the Gathering System under the Agreement, and (b) Shipper agrees not to deliver any Dedicated Production to any other gathering system (the foregoing dedication and commitment being herein referred to as the "Dedication").

3. Covenant Running with the Land. So long as the Agreement is in effect, Dedication shall be a covenant running with the land and, subject to the exceptions and reservations set forth in the Agreement, (a) in the event Shipper sells, transfers, conveys, assigns, grants, or otherwise disposes of any or all of its interest in the Dedicated Properties, then any such sale, transfer, conveyance, assignment, grant, or other disposition shall be expressly subject to this Agreement and any instrument of conveyance shall so state, and (b) in the event Gatherer sells, transfers, conveys, assigns, grants, or otherwise disposes of any or all of its interest in the Gathering

System, then any such sale, transfer, conveyance, assignment, grant, or other disposition shall be expressly subject to this Agreement and any instrument of conveyance shall so state.

4 . No Amendment to Agreement. This Memorandum is executed and recorded solely for the purpose of giving notice and shall not amend nor modify the Agreement in any way.

IN WITNESS WHEREOF, this Memorandum has been signed by or on behalf of each of the Parties as of the Day first above written.

ANTERO MIDSTREAM LLC

By: ______________________________
Name: ______________________________
Title: ______________________________

ANTERO RESOURCES CORPORATION

By: ______________________________
Name: ______________________________
Title: ______________________________

ACKNOWLEDGEMENTS

STATE OF COLORADO §
§
CITY AND COUNTY OF DENVER §

The foregoing instrument was acknowledged before me on the ______ Day of ________, ______, by [____________], [____________] of Antero Midstream LLC, a Delaware limited liability company, on behalf of said entity.

____
Notary Public in and for ______________

____
Printed or Typed Name of Notary

STATE OF COLORADO §
§
CITY AND COUNTY OF DENVER §

The foregoing instrument was acknowledged before me on the ______ Day of _______, ______, by [____________], [____________] of Antero Resources Corporation, a Delaware corporation, on behalf of said entity.

____
Notary Public in and for ______________

____
Printed or Typed Name of Notary

Exhibit 10.7

Execution Version

AMENDED AND RESTATED

SECONDMENT AGREEMENT

by and among **ANTERO MIDSTREAM CORPORATION**

ANTERO MIDSTREAM PARTNERS LP

ANTERO MIDSTREAM PARTNERS GP LLC

ANTERO MIDSTREAM LLC

ANTERO WATER LLC

ANTERO TREATMENT LLC

and

ANTERO RESOURCES CORPORATION

December 31, 2019

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SCHEDULES

AMENDED AND RESTATED SECONDMENT AGREEMENT

THIS AMENDED AND RESTATED SECONDMENT AGREEMENT is made effective as of December 31, 2019, by and among Antero Midstream Corporation, a Delaware corporation (the "***Company***"), Antero Midstream Partners LP, a Delaware limited partnership and an indirectly wholly-owned subsidiary of the Company ("***Antero Partners***"), Antero Midstream Partners GP LLC, a Delaware limited liability company that is disregarded as separate from the Company for U.S. federal income tax purposes (the "***General Partner***"), Antero Midstream LLC, a Delaware limited liability company and a wholly-owned subsidiary of Antero Partners ("***Antero Midstream***"), Antero Water LLC, a Delaware limited liability company and a wholly-owned subsidiary of Antero Partners ("***Antero Water***"), Antero Treatment LLC, a Delaware limited liability company and a wholly-owned subsidiary of Antero Partners ("***Antero Treatment***") and Antero Resources Corporation, a Delaware corporation ("***Antero***"). The Company, Antero Partners, the General Partner, Antero Midstream, Antero Water and Antero are sometimes referred to herein separately as "***Party***" or collectively as the "***Parties***."

RECITALS

WHEREAS, each of Antero Partners, Antero Midstream, Antero Water, Antero Treatment, Antero and Antero Resources Midstream Management LLC, a Delaware limited liability company and predecessor in interest to the General Partner, entered into a Secondment Agreement dated September 23, 2015 (the "***Initial Secondment Agreement***"), and the Parties intend to amend and restate such Initial Secondment Agreement in its entirety as set forth herein;

WHEREAS, Antero Partners, directly or indirectly, owns (i) the Gathering Facilities (as defined below) consisting of gathering pipelines, compressor stations and certain other associated midstream assets and (ii) the Water Assets (as defined below) consisting of water delivery pipelines, water treatment and other water facilities and related assets;

WHEREAS, the Company, Antero Partners and the other members of the Company Group (as defined below) desire that Antero provide Seconded Employees (as defined below) to perform the Operating Services (as defined below) with respect to the Gathering Facilities and the Water Assets in accordance with the following commercial agreements (i) that certain First Amended Gathering and Compression Agreement, dated as of February 13, 2018, between Antero and Antero Midstream (as further amended, supplemented or restated from time to time, the "***Gathering Agreement***"), (ii) that certain Second Amended Right of First Offer Agreement, dated as of February 13, 2018, between Antero and Antero Midstream (as further amended, supplemented or restated from time to time, the "***ROFO Agreement***"), (iii) that certain Amended and Restated Water Services Agreement, dated as of February 12, 2019, between Antero and Antero Water (as further amended, supplemented or restated from time to time, the "***Water Services Agreement***") and (iv) any agreements between members of the Partnership Group and certain third parties pursuant to which the members of the Partnership Group require Operating Services (such agreements, "***Third Party Agreements***"); and

WHEREAS, the Parties desire to set forth their respective rights and responsibilities with respect to (i) Antero's secondment of employees for purposes of the operation, maintenance and management of the Gathering Facilities and the Water Assets and (ii) the provision of any other Operating Services.

NOW THEREFORE, in consideration of their mutual undertakings and agreements hereunder, the Parties agree that the above-described Initial Secondment Agreement shall hereby be amended and restated in its entirety as follows:

AGREEMENT

NOW, THEREFORE, the Parties hereby agree as follows:

ARTICLE I
DEFINITIONS, CONSTRUCTION

1.1 ***Definitions***. In this Agreement, capitalized terms used, but not otherwise defined, shall have the respective meanings given to such terms set forth below:

A&R Services Agreement shall have the meaning set forth in Section 11.4.

Accounting Procedures shall have the meaning set forth in Schedule 2.

Affiliate means (i) with respect to Antero, any Person that directly or indirectly through one or more intermediaries is controlled by Antero (excluding, for the avoidance of doubt, the Company and any other Person that directly or indirectly through one or more intermediaries is controlled by the Company); (ii) with respect to the Company, any Person that directly or indirectly through one or more intermediaries is controlled by the Company; and (iii) with respect to Antero Partners, the General Partner and any other Person that directly or indirectly through one or more intermediaries is controlled by the General Partner. As used herein, the term "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

Affiliated Group shall have the meaning set forth on Schedule 2.

Agreement means this Amended and Restated Secondment Agreement, as the same may be amended.

Antero shall have the meaning set forth in the first paragraph.

Antero Group shall have the meaning set forth in Section 4.1.

Antero Indemnitees shall have the meaning set forth in Section 9.2.

Antero Midstream shall have the meaning set forth in the first paragraph.

Antero Partners shall have the meaning set forth in the first paragraph.

Antero Water shall have the meaning set forth in the first paragraph.

Applicable Law means all laws, permits, rules, codes, ordinances, requirements and regulations of all federal, state or local agencies, court and other governmental bodies, including the Natural Gas Act, the Pipeline Safety Act of 1968, both as amended, and the regulations and orders of the Federal Energy Regulatory Commission and the Department of Transportation; in each case, as applicable to Antero, the Company, Antero Partners, any other member of the Company Group, or the Assets.

Assets means the Water Assets, the Gathering Facilities, and any future assets of any member of the Company Group that do not constitute Water Assets or Gathering Facilities.

Audit Committee means the Audit Committee of the Board of Directors of the Company.

Business Day means any day other than a Saturday, a Sunday, or a holiday on which national banking associations in the State of Colorado are closed.

Capital Expenditures means all Expenditures that are capitalized, as applicable in accordance with GAAP and the relevant Party's accounting capitalization procedures, in each case as consistently applied and as in effect from time to time.

Code means the Internal Revenue Code of 1986, as amended.

Commercial Agreements shall mean the Gathering Agreement, the ROFO Agreement, the Water Services Agreement, the Third Party Agreements and any future agreements entered into with respect to the Assets that require the provision of Operating Services.

Company shall have the meaning set forth in the first paragraph.

Company Group shall mean the Company, Antero Midstream NewCo Inc., Antero IDR Holdings LLC, the General Partner, the members of the Partnership Group, and any other entity directly or indirectly wholly owned by the Company.

Company Indemnitees shall have the meaning set forth in Section 9.2.

Expenditure means a cost, expense or expenditure.

Fiscal Year means each 12 month period beginning on the first day of January of a year and ending on December 31 of the same year; *provided*, the last Fiscal Year shall end at the expiration or termination of this Agreement.

Force Majeure shall have the meaning set forth in Section 10.1(b).

GAAP means United States generally accepted accounting principles as in effect from time to time.

Gathering Agreement shall have the meaning set forth in the Recitals.

Gathering Facilities shall mean (a) the Gathering System (as defined in the Gathering Agreement), (b) any property, equipment or other assets associated with the provision of Services (as defined in the ROFO Agreement) under the ROFO Agreement, (c) any other assets, equipment, accessions and improvements in respect of the foregoing owned, directly or indirectly, by the Partnership Group, and (d) any other assets, equipment or facilities owned by the Partnership Group as of the date of this Agreement other than the Water Assets.

General Partner shall have the meaning set forth in the first paragraph.

Governmental Authority means any governmental authority, agency, department, commission, bureau, board, instrumentality, court or quasi-governmental authority of any foreign nation, the United States, or any state that has or obtains jurisdiction over the matter in question, or any political subdivision thereof.

Initial Secondment Agreement shall have the meaning set forth in the Recitals.

Initial Services Agreement means the Services Agreement dated November 10, 2014, by and among Antero, Antero Partners and Antero Resources Midstream Management LLC.

Liability shall have the meaning set forth in Section 9.3(a).

Month means a calendar month.

Operating Services have the meaning set forth in Section 2.1.

Partnership Group means Antero Partners and its direct and indirect subsidiaries, including Antero Water, Antero Treatment and Antero Midstream.

Party or ***Parties*** means any of the entities named in the first paragraph to this Agreement and any respective successors or permitted assigns in accordance with the provisions of this Agreement.

Period of Secondment shall have the meaning set forth in Section 3.1(b).

Permit means all permits, licenses, franchises, consents, authorizations, certifications, exemptions, variances, and approvals, as necessary under Applicable Laws for operating the Assets.

Person means any natural person, corporation, limited liability company, partnership, joint venture, trust, unincorporated organization, association, joint stock company or Governmental Authority.

Prior Contribution Agreement means that certain Amended and Restated Contribution Agreement, dated as of November 10, 2014, between Antero and Antero Partners, as amended, supplemented or restated from time to time.

ROFO Agreement shall have the meaning set forth in the Recitals.

Seconded Employee(s) shall have the meaning set forth in Section 3.1(b).

Treasury Regulations means pronouncements, as amended from time to time, or their successor pronouncements, that clarify, interpret and apply the provisions of the Code, and that are designated as "Treasury Regulations" by the United States Department of the Treasury.

Water Assets shall have the meaning provided such term in the Water Contribution Agreement, as well as any future assets of Antero Water, Antero Treatment or any other Affiliate of Antero Partners to the extent relating to the water businesses of those respective entities.

Water Contribution Agreement means that certain Contribution, Conveyance, and Assumption Agreement, dated as of September 17, 2015, by and among Antero, Antero Partners, and Antero Treatment, as amended, supplemented or restated from time to time.

Water Services Agreement shall have the meaning set forth in the Recitals.

1.2 ***Construction***. In construing this Agreement, the following principles shall be followed: (a) no consideration shall be given to the captions of articles, sections or subsections; (b) no consideration shall be given to the fact or presumption that one Party had a greater or lesser hand in drafting this Agreement; (c) the word "includes" and its syntactic variants means "includes, but is not limited to" and corresponding syntactic variant expressions; (d) the plural shall be deemed to include the singular, and vice versa; (e) the words "this Agreement," "herein," "hereby," "hereunder" and "hereof," and words of similar import, refer to this Agreement as a whole and not to any particular subdivision unless expressly so limited; (f) the words "this Article," "this Section" and "this clause," and words of similar import, refer only to the Article, Section or clause hereof in which such words occur; and (g) the word "or" is not exclusive, and the word "including" (in its various forms) means including without limitation.

ARTICLE II
SECONDMENT

2.1 ***Seconded Employees of Antero***. Subject to the terms of this Agreement, Antero agrees to provide Seconded Employees (as defined in Section 3.1(b)), who, in their capacity as Seconded Employees of the Company, a member of the Partnership Group and any other member of the Company Group, as applicable, will perform the services described on Schedule 1 and such additional services as the Parties may agree in writing from time to time, except as outsourced by the Company or any other member of the Company Group to third party service providers (collectively, the "***Operating Services***"), in order for Antero Partners and the other members of the Company Group to operate the Assets in an efficient manner, and in a manner that permits the applicable Parties to comply with their obligations under the Commercial Agreements. The Seconded Employees will perform the Operating Services in accordance with the terms and conditions and subject to the limitations set forth in this Agreement.

2.2 ***Direction and Control of Seconded Employees***. Subject to the provisions of Section 3.1(d), each Seconded Employee shall be subject to the direction and control of the Company and any other member of the Company Group for which the Seconded Employee is providing the Operating Services. Antero shall respond in a commercially reasonable manner to all instructions, notices, requests or inquiries from the Company and each member of the Company Group with respect to the Seconded Employees. Decisions, acts or omissions so undertaken by the

Seconded Employees or Antero with respect to the Seconded Employees pursuant to the direction and control of any member of the Company Group shall not give rise to any breach of or default under this Agreement by Antero or liability to Antero provided that Antero otherwise acted in accordance with the requirements of Section 2.1.

2.3 ***Termination of Seconded Employees***. The Company and the other members of the Company Group shall have no authority to terminate a Seconded Employee's employment with Antero; *provided, however*, that the relevant member of the Company Group may terminate the Seconded Employee's secondment to such entity. Antero shall, at all times, have sole authority to terminate a Seconded Employee's employment with Antero.

2.4 ***Supervision and Management of the Seconded Employees***. To the extent that supervisors or managers of Seconded Employees issue instructions to such Seconded Employees regarding the Operating Services, such supervisors and managers shall be treated for purposes of this Agreement as acting on behalf of the member of the Company Group for which such Seconded Employees are providing Operating Services.

2.5 ***Consultations***. Antero, the Company and Antero Partners shall consult as frequently as reasonably necessary regarding the scope of Operating Services to be performed by the Seconded Employees and particular circumstances that may require an adjustment to Antero's obligation to provide the Seconded Employees, and shall keep each other timely informed about planned downtime, major maintenance projects, capital projects, significant operational events and other major events that are relevant to the safe and efficient operation of the Assets and the performance of the Parties' respective obligations under this Agreement.

2.6 ***Additional Seconded Employees and Additional Services***. If, subsequent to the date hereof, additional services not listed on Schedule 1 are required to operate the Assets or to operate any other business of a member of the Company Group, Antero shall use commercially reasonable efforts to provide Seconded Employees to operate the Assets or such other business and provide such additional services on mutually agreeable pricing and other terms to be determined on a basis similar to the pricing and other terms set forth in this Agreement, whereupon such additional services shall be considered part of the Operating Services.

2.7 ***Title to Items Obtained on Behalf of the Company Group***. To the extent that any materials, equipment, supplies, consumables, spare parts and other items are purchased or obtained by Antero or its Affiliates for or on behalf of any member of the Company Group, title to such items shall pass immediately to and vest in such member of the Company Group upon passage of title from the vendor or supplier thereof free and clear of all liens or encumbrances arising by, through and under Antero and its Affiliates but not otherwise (other than liens and security interests securing any unpaid portion of the purchase price for the same). All materials, data and documents, to the extent prepared or developed by any Seconded Employee during the term of this Agreement for any member of the Company Group or their respective Affiliates in connection with the Seconded Employees' performance of the Operating Services, including all manuals, data, designs, drawings, plans, specifications and reports, shall belong to such member of the Company Group or such respective Affiliate. All such materials, documents and data, in whatever form, including electronic copies and databases, shall be provided promptly to such member of the Company Group following any termination of this Agreement, or at such other times as such member of the Company Group may reasonably direct; *provided, however*, that Antero shall be entitled to retain (a) copies of such materials, documents and data for document retention and compliance purposes if required by law, rules, regulations or orders of the court and (b) all electronic copies (if any) of any such materials, documents and data residing in its (and its Affiliates') automatic backup systems.

ARTICLE III
EMPLOYEES

3.1 ***Personnel***.

(a) Pursuant to Section 2.1, Antero shall second to the Company and any member of the Partnership Group or any other member of the Company Group for which the Seconded Employee is providing Operating Services, the Seconded Employees (as defined in Section 3.1(b)) as Antero deems necessary or appropriate in order to perform the Operating Services in an efficient and prudent manner. Subject to Antero's right to be reimbursed for such expenses in accordance with the Accounting Procedures, Antero shall pay all expenses charged to or incurred by it in connection with the retention of the Seconded Employees, including compensation, salaries, wages and overhead and administrative expenses and if applicable, payroll taxes, workers compensation insurance, retirement and insurance benefits and other applicable expenses. Any such Seconded Employees retained by Antero may be union or non-union employees, and Antero shall have the sole right to negotiate the terms and provisions of any labor or other agreements with the unions to which such Seconded Employees belong. Any Seconded Employee performing Operating Services shall be seconded by Antero to the Company and any member of the Partnership Group or any other member of the Company Group for which such Seconded Employee is providing Operating Services, as applicable.

(b) During the term of this Agreement, Antero shall, from time to time, designate certain of its employees to be seconded to the Company, a member of the Partnership Group or any other member of the Company Group, as applicable, to provide Operating Services, perform duties with respect to the Assets or otherwise work on behalf of the Company, a member of the Partnership Group or any other member of the Company Group in accordance with and subject to the terms of this Agreement. Each such employee that Antero seconds to the Company, a member of the Partnership Group or any other member of the Company Group to provide Operating Services for such entity shall, during the time that such employee is seconded to the Company, a member of the Partnership Group or any other member of the Company Group under this Agreement (such time period, the "***Period of Secondment***"), be referred to individually herein as a "***Seconded Employee***" and, collectively, as the "***Seconded Employees***." The employment of the Seconded Employees by Antero and the Company during their Period of Secondment shall constitute "concurrent employment" (as defined in Treasury Regulations § 31.3121(s)-1(b)(3)).

(c) At the request of the Company, the Partnership or another member of the Company Group, Antero shall notify each Seconded Employee of such employee's secondment. The notice of such secondment provided to each Seconded Employee may state that (i) each such Seconded Employee will be a joint employee of Antero, the Company and any other member of the Company Group for which such Seconded Employee is providing Operating Services, and (ii) for any workplace injury, the Seconded Employee's sole remedy against either Antero, the Company, any other member of the Company Group, and each of their respective Affiliates will be under the workers' compensation insurance policy or qualified self-insured program of Antero. For the avoidance of doubt, the Parties acknowledge that the Seconded Employees will, during the Period of Secondment, be called upon to perform services for both members of the Company Group and Antero (and their respective applicable Affiliates) of the same or closely-related nature. Antero retains the right to terminate the secondment of any Seconded Employee for any reason at any time or to hire or discharge the Seconded Employees with respect to their employment with Antero. The Company and the other members of the Company Group for which the Seconded Employees provide Operating Services will have the right to terminate the secondment to it of any Seconded Employee for any reason at any time, upon prior written notice to Antero, but at no time will the Company or any other member of the Company Group have the right to terminate any Seconded Employee's employment by Antero. Upon the termination of the secondment of any Seconded Employee for any reason, such Seconded Employee will cease performing services for the Company Group and shall cease to be jointly employed by Antero, the Company and any other member of the Company Group.

(d) Each Seconded Employee shall be under the direction and control of the Company and any other member of the Company Group for which such Seconded Employee provides Operating Services. To the extent Operating Services are performed for the Partnership Group, the Parties acknowledge that the Seconded Employees shall report into the management structure of Antero Partners and, accordingly, shall be under the direct management, supervision, direction and control of the Company as a result of the Company's control of the General Partner, which controls Antero Partners.

(e) Those Seconded Employees who serve as supervisors or managers and who are called upon to oversee the work of Seconded Employees with respect to the Assets or to provide management support on behalf of a member of the Company Group are designated by such member of the Company Group as supervisors to act on the behalf of such member of the Company Group in supervising the Seconded Employees pursuant to <u>Section 3.1(d)</u>. Any Seconded Employee so designated will be acting on the behalf of the relevant member of the Company Group when supervising the work of the Seconded Employees or when they are otherwise providing management or executive support on behalf of such member of the Company Group.

(f) With respect to the Company Group's operations in Ohio, Antero shall obtain workers' compensation coverage as defined by Ohio Revised Code Chapter 4123 on behalf of Antero and the members of the Company Group for which the Seconded Employees are providing Operating Services, and each such member of the

Company Group shall be considered an employer solely for the purposes of Ohio Revised Code Chapter 4123. With respect to the Company Group's operations in West Virginia, Antero shall obtain workers' compensation coverage as defined by West Virginia Code Chapter 23 on behalf of Antero and the members of the Company Group for which the Seconded Employees are providing Operating Services, and each such members of the Company Group shall be considered a special employer solely for the purposes of West Virginia Code Chapter 23. With respect to the Company Group's operations in Pennsylvania, Antero shall obtain workers' compensation coverage as defined by Pennsylvania Statutes Title 77 on behalf of Antero and the members of the Company Group for which the Seconded Employees are providing Operating Services, and the Company and each such members of the Company Group shall be considered a statutory employer solely for the purposes of Pennsylvania Statutes Title 77 § 481. With respect to the Company Group's operations in Colorado, Antero shall obtain workers' compensation coverage as defined by Colorado Revised Statutes Title 8 on behalf of Antero and the members of the Company Group for which the Seconded Employees are providing Operating Services, and the Company and each such members of the Company Group shall be considered a statutory employer solely for the purposes of Colorado Revised Statutes Title 8, Articles 40 to 47. For the avoidance of doubt, nothing in this Agreement has any effect on the right of a Seconded Employee to prosecute a workers' compensation claim against Antero or any member of the Company Group for which such Seconded Employee is providing Operating Services.

(g) Neither the Company nor any other member of the Company Group for which the Seconded Employees are providing Operating Services shall be a participating employer in any benefit plan of Antero or any of its Affiliates. Antero shall remain solely responsible for all obligations and liabilities arising with respect to any benefit plans relating to any Seconded Employees, and the Company Group shall not assume any benefit plan or have any obligations or liabilities arising thereunder, in each case except for costs properly chargeable to the Company Group under this Agreement.

ARTICLE IV
REIMBURSEMENT AND BILLING PROCEDURES

4.1 ***Reimbursement***. Subject to and in accordance with the terms and provisions of this Article IV (but without duplication of any amounts due pursuant to the A&R Services Agreement) and taking into account any reasonable allocation and other procedures as may be agreed upon from time to time by Antero, the Company and the General Partner, the Company shall reimburse Antero for all direct and indirect costs and expenses incurred by Antero and its Affiliates (collectively, the "***Antero Group***") in connection with the provision of the Operating Services for the Company and any other member of the Company Group; *provided, however*, Antero Partners shall reimburse Antero for all direct and indirect costs and expenses incurred by the Antero Group in connection with the provision of the Operating Services for Antero Partners and any other member of the Partnership Group. Such reimbursement shall include reimbursement for the following:

(a) Expenditures and Capital Expenditures incurred in the performance of the Operating Services, in accordance with the Accounting Procedures; *provided*, *however*, Antero shall not be reimbursed for Expenditures for which Antero is required to provide indemnification to Antero Partners or any other Company Indemnitee pursuant to Section 9.3(b);

(b) any payments or expenses incurred for insurance coverage, including allocable portions of premiums, and negotiated instruments (including surety bonds and performance bonds) provided by underwriters with respect to the Assets, the Company Group's other assets or the businesses of the Company Group; and

(c) salaries and related benefits and expenses of personnel employed by the Antero Group who render Operating Services, plus general and administrative expenses to the extent associated with such personnel (including the cost of workers' compensation insurance coverage with respect to such periods that the Seconded Employees are providing Operating Services);

it being agreed, however, that to the extent any reimbursable costs or expenses incurred by the Antero Group consist of an allocated portion of costs and expenses incurred by the Antero Group for the benefit of both any member of the Company Group and any member of the Antero Group, an allocation of such reimbursable costs or expenses shall be made on a reasonable basis as determined by Antero in good faith.

4.2 ***Billing Procedures***. The Company shall pay or cause to be paid Antero or any other applicable member of the Antero Group providing the Operating Services for billed costs and expenses no later than the later of (i) the last day of the Month following the performance Month or (ii) thirty (30) Business Days following the date of the billing of such costs and expenses. Payments made under this Agreement shall be made in cash, by wire transfer or by offset to other amounts due and owing from one Party to another; *provided, however*, that any offset shall be documented and such documentation shall be provided to the relevant Party upon request. The Company and the Partnership shall have the right to review all source documentation concerning the liabilities, costs and expenses allocated to the Company, the Partnership and any other members of the Company Group upon reasonable notice and during regular business hours.

4.3 ***Reports***. Antero shall cause to be timely prepared and delivered to the applicable member of the Company Group such reports, forecasts, implementation plans, plans of action, studies and other information pertaining to the performance of the Operating Services as such member of the Company Group may reasonably request from time to time. The costs incurred by Antero in preparing and delivering such reports, forecasts, plans, studies and other information shall be included in the Expenditures to be reimbursed by the Company or Antero Partners, as applicable, pursuant to Section 4.1(a).

4.4 ***Audit and Examination***. The Company and Antero Partners shall have the right to review and contest the expenses charged pursuant to the terms of this Agreement in accordance with this Section 4.4. The Company and Antero Partners, as applicable, shall have the right, upon reasonable notice and at reasonable times, to inspect and audit all the records, books, reports, data and processes related to the Operating Services performed by Antero to ensure Antero's compliance with the terms of this Agreement. If any such examination establishes an inaccuracy, necessary adjustments will be made promptly. If any information provided to or reviewed by the Company or Antero Partners under this Section 4.4(a) is confidential, the relevant Parties shall execute a mutually acceptable confidentiality agreement prior to such inspection or audit.

ARTICLE V
STANDARD OF CARE, NEGATIVE COVENANTS

5.1 ***Standard of Care***. Antero shall second the Seconded Employees, who will perform the Operating Services and who shall carry out their responsibilities (a) in accordance with workmanlike practices common in the U.S. oil and natural gas industry, and exercise the same level of care Antero requires in the management of its own business and affairs, and (b) in compliance with all environmental laws, rules and regulations of the United States of America and the states where the Assets are located.

5.2 ***Negative Covenants***. For the avoidance of doubt, no member of the Antero Group shall, without the prior written consent of the Company and Antero Partners, do or, to the extent the same is within its reasonable control and consistent with the other terms of this Agreement, permit to occur or to continue to occur, or permit any Seconded Employee to do or permit to occur or continue to occur, any of the following:

(a) commit any member of the Company Group to, or enter into on behalf of the Company Group, any contract or agreement;

(b) create or incur any lien, security interest or encumbrance upon the Assets, including any mechanics or materialmen's liens or similar encumbrances arising out of claims for work, labor or materials furnished in connection with the provision of Operating Services;

(c) purport to sell, lease, pledge, mortgage, assign, transfer or otherwise dispose of the Assets or any other assets of the Company Group now owned or hereafter acquired; or

(d) commit any member of the Company Group to be or to become directly or contingently responsible or liable for obligations of any other Person, by assumption, guarantee, endorsement or otherwise.

ARTICLE VI
TAXES

6.1 ***Embedded Tax Amounts***. If any portion of any payment made by the Company or Antero Partners hereunder is to reimburse Antero for any U.S. federal, state or local taxes or assessments, then Antero shall cause such taxes and assessments to be paid prior to delinquency.

6.2 ***Income Taxes***. Notwithstanding anything to the contrary, Expenditures for which Antero is entitled to reimbursement pursuant to this Agreement shall not include taxes that are measured or based on Antero's income, franchise or similar taxes, and all such income, franchise and similar taxes shall be the responsibility of Antero.

6.3 ***Common Paymaster***. Antero shall serve as the common paymaster, within the meaning of Section 3121(s) of the Code, for the Company and any other applicable member of the Company Group with respect to the Seconded Employees, and, in such capacity, shall timely (a) pay and deliver to the appropriate U.S. federal, state and local taxing authorities all payroll and income taxes withheld from, or payable with respect to, the compensation of the Seconded Employees and (b) file all information returns required under Applicable Law.

ARTICLE VII
TERMINATION

7.1 ***Term***. Unless terminated earlier, this Agreement shall continue in effect until the twentieth (20^{th}) anniversary of the execution of the Initial Services Agreement and from year to year thereafter (with the initial term of this Agreement deemed extended for each of any such additional year) until such time as this Agreement is terminated. Any termination of this Agreement during any such year to year extension of the initial term shall be effected by written notice of such termination from either Party to the other Party on or before the one hundred eightieth (180^{th}) day prior to the next anniversary of the execution of the Initial Services Agreement with such termination effective upon the occurrence of such next anniversary.

7.2 ***Termination***.

(a) Notwithstanding anything to the contrary in this Agreement, this Agreement may be terminated at any time (i) in its entirety by mutual written agreement of all of the Parties to the Agreement, (ii)with respect to the Company, by the Company, in its sole discretion, effective upon delivery of written notice of such termination to Antero and (iii)with respect to Antero Partners, by Antero Partners, in its sole discretion, effective upon delivery of written notice of such termination to Antero.

(b) Upon termination of this Agreement, all rights and obligations of the Parties under this Agreement shall terminate, *provided*, *however*, that such termination shall not affect or excuse the performance of any party under the provisions of Article IX, which provisions shall survive the termination of this Agreement indefinitely, or the obligations under Article IV with respect to amounts relating to periods prior to the termination of this Agreement, which provisions shall survive until such amounts are paid in full.

ARTICLE VIII
ACCESS TO THE ASSETS

The Seconded Employees shall at all times during their performance of the Operating Services hereunder have full and free, non-exclusive access to the Assets as necessary to perform their obligations under this Agreement, and all such Persons shall comply with all safety and other procedures from time to time imposed by the Company, Antero Partners or any other member of the Company Group in connection with any access to or work performed on or about the Assets.

ARTICLE IX
INDEMNIFICATION

9 . 1 ***Indemnification Scope***. IT IS IN THE BEST INTERESTS OF THE PARTIES THAT CERTAIN RISKS RELATING TO THE MATTERS GOVERNED BY THIS AGREEMENT SHOULD BE IDENTIFIED AND ALLOCATED AS BETWEEN THEM. IT IS THEREFORE THE INTENT AND PURPOSE OF THIS AGREEMENT TO PROVIDE FOR THE INDEMNITIES SET FORTH HEREIN TO THE MAXIMUM EXTENT ALLOWED BY LAW. ALL PROVISIONS OF THIS ARTICLE SHALL BE DEEMED CONSPICUOUS WHETHER OR NOT CAPITALIZED OR OTHERWISE EMPHASIZED.

9.2 ***Indemnified Persons***. Wherever the "Company" or "Antero" appears as an indemnitee in this Article, the term shall include that entity and its Affiliates, and the respective agents, officers, directors, employees, representatives and contractors and subcontractors of any tier of the foregoing entities involved in actions or duties to act on behalf of the indemnified Party. These groups will be the "***Company Indemnitees***" or the "***Antero Indemnitees***" as applicable, *provided*, *however*, that for the avoidance of doubt, the Company Indemnitees shall not include Antero and its Affiliates, and the Antero Indemnitees shall not include the Company or any member of the Company Group. "Third parties" shall not include any Company Indemnitees or Antero Indemnitees.

9.3 ***Indemnifications***.

(a) THE COMPANY OR ANTERO PARTNERS, AS APPLICABLE, SHALL RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS THE ANTERO INDEMNITEES FROM AND AGAINST ANY AND ALL CLAIMS, CAUSES OF ACTION, DEMANDS, LIABILITIES, LOSSES, DAMAGES, FINES, PENALTIES, JUDGMENTS, EXPENSES AND COSTS, INCLUDING REASONABLE ATTORNEYS' FEES AND COSTS OF INVESTIGATION AND DEFENSE (EACH, A "***LIABILITY***") (INCLUDING, WITHOUT LIMITATION, ANY LIABILITY FOR (i) DAMAGE, LOSS OR DESTRUCTION OF THE ASSETS, (ii) BODILY INJURY, ILLNESS OR DEATH OF ANY PERSON, EXCEPT TO THE EXTENT SUCH PERSON IS A SECONDED EMPLOYEE, AND (iii) LOSS OF OR DAMAGE TO EQUIPMENT OR PROPERTY OF ANY PERSON) IN EACH CASE ARISING FROM OR RELATING TO THE SECONDED EMPLOYEES' PERFORMANCE OF THIS AGREEMENT, EXCEPT TO THE EXTENT SUCH LIABILITY IS CAUSED BY THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE ANTERO INDEMNITEES.

(b) ANTERO SHALL RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS THE COMPANY INDEMNITEES FROM AND AGAINST ANY AND ALL LIABILITIES (INCLUDING, WITHOUT LIMITATION, ANY LIABILITY FOR (i) DAMAGE, LOSS OR DESTRUCTION OF THE ASSETS, (ii) BODILY INJURY, ILLNESS OR DEATH OF ANY PERSON, EXCEPT TO THE EXTENT SUCH PERSON IS A SECONDED EMPLOYEE, AND (iii) LOSS OF OR DAMAGE TO EQUIPMENT OR PROPERTY OF ANY PERSON) IN EACH CASE ARISING FROM OR RELATING TO THE SECONDED EMPLOYEES' PERFORMANCE UNDER THIS AGREEMENT TO THE EXTENT SUCH LIABILITY IS CAUSED BY THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE ANTERO INDEMNITEES.

9.4 ***Damages Limitations***. Any and all damages recovered by either Party pursuant to this Article IX or pursuant to any other provision of or actions or omissions under this Agreement shall be limited to actual damages. CONSEQUENTIAL DAMAGES AND EXEMPLARY AND PUNITIVE DAMAGES SHALL NOT BE RECOVERABLE UNDER ANY CIRCUMSTANCES EXCEPT TO THE EXTENT THOSE DAMAGES ARE INCLUDED IN THIRD PARTY CLAIMS FOR WHICH A PARTY HAS AGREED HEREIN TO INDEMNIFY THE OTHER PARTY. EACH PARTY ACKNOWLEDGES IT IS AWARE THAT IT HAS POTENTIALLY VARIABLE LEGAL RIGHTS UNDER COMMON LAW AND BY STATUTE TO RECOVER CONSEQUENTIAL, EXEMPLARY, AND PUNITIVE DAMAGES UNDER CERTAIN CIRCUMSTANCES, AND, EXCEPT AS PROVIDED IN THE PRECEDING SENTENCE WITH RESPECT TO THIRD PARTY CLAIMS, EACH PARTY NEVERTHELESS WAIVES, RELEASES, RELINQUISHES, AND SURRENDERS RIGHTS TO CONSEQUENTIAL PUNITIVE AND EXEMPLARY DAMAGES TO THE FULLEST EXTENT PERMITTED BY LAW WITH FULL KNOWLEDGE AND AWARENESS OF THE CONSEQUENCES OF THE WAIVER REGARDLESS OF THE NEGLIGENCE OR FAULT OF EITHER PARTY.

9.5 ***Defense of Claims***. The indemnifying Party shall defend, at its sole expense, any claim, demand, loss, liability, damage, or other cause of action within the scope of the indemnifying Party's indemnification obligations under this Agreement, *provided* that the indemnified Party notifies the indemnifying Party promptly in writing of any claim, loss, liability, damage, or cause of action against the indemnified Party and gives the indemnifying Party information, and assistance at the reasonable expense of the indemnifying Party in defense of the matter. The indemnified Party may be represented by its own counsel (at the indemnified Party's sole expense) and may participate in any proceeding relating to a claim, loss, liability, damage, or cause of action in which the indemnified Party or both Parties are defendants, *provided*, *however*, the indemnifying Party shall, at all times, control the defense and any appeal or settlement of any matter for which it has indemnification obligations under this Agreement so long as any such settlement includes an unconditional release of the indemnified Party from all liability arising out of such claim, demand, loss, liability, damage, or other cause of action and does not require any remediation or other action other than the payment of money which the indemnifying party will be responsible for hereunder and does not include a statement as to or an admission of fault, culpability or a failure to act by or on behalf of the indemnified Party. Should the Parties both be named as defendants in any third-party claim or cause of action arising out of or relating to the Assets or Operating Services, the Parties will cooperate with each other in the joint defense of their common interests to the extent permitted by law, and will enter into an agreement for joint defense of the action if the Parties mutually agree that the execution of the same would be beneficial.

ARTICLE X
FORCE MAJEURE

10.1 ***Force Majeure Event.***

(a) In the event a Party is rendered unable, wholly or in part, by Force Majeure to carry out its obligations under this Agreement, other than the obligation to make payments then or thereafter due hereunder, and such Party promptly gives notice and reasonably full particulars of such Force Majeure to the other Party promptly after the occurrence of the cause relied on, then the obligations of the Party giving such notice, so far as and to the extent that they are affected by Force Majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as reasonably possible be remedied with all reasonably dispatch by the Party claiming Force Majeure.

(b) "***Force Majeure***" as used in this Agreement shall mean any cause or causes not reasonably within the control of the Party claiming suspension and which, by the exercise of reasonable diligence, such Party is unable to prevent or overcome, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, acts of terror, sabotage, wars, blockades, military action, insurrections, riots, epidemics, landslides, subsidence, lightning, earthquakes, fires, storms or storm warnings, crevasses, floods, washouts, civil disturbances, explosions, breakage or accidents to wells, machinery, equipment or lines of pipe; the necessity for testing or making repairs or alterations to wells, machinery, equipment or lines of pipe, freezing of wells, equipment or lines of pipe; inability of any Party hereto to obtain, after the exercise of reasonable diligence, necessary materials, supplies or governmental approvals; and action or restraint by any Governmental Authority (so long as the Party claiming suspension has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such action or restraint, and as long as such action or restraint is not the result of a failure by the claiming Party to comply with any Applicable Law).

(c) The settlement of any strikes or lockouts will be entirely within the discretion of Antero, and settlement of strikes, lockouts or other labor disturbances when that course is considered inadvisable is not required.

ARTICLE XI
OTHER PROVISIONS

11.1 ***Assignment***. This Agreement shall be binding upon and inure to the benefit of the Parties named herein. No Party may assign or otherwise transfer either this Agreement or any of its rights, interests or obligations hereunder without the prior written approval of the other Parties, which approval shall not be unreasonably withheld, conditioned or delayed.

11.2 ***Notices***. All notices or requests or consents provided for by, or permitted to be given pursuant to, this Agreement must be in writing and must be given by depositing the same in the U.S. mail, addressed to the Party to be notified, postpaid, and registered or certified with return receipt requested or by delivering such notice in person or by facsimile or e-mail to such Party. Notice given by personal delivery or mail shall be effective upon actual receipt. Notice given by facsimile or e-mail shall be effective upon actual receipt if received during the recipient's normal business hours or at the beginning of the recipient's next Business Day after receipt if not received during the recipient's normal business hours. All notices to be sent to a Party pursuant to this Agreement shall be sent to or made at the address set forth below or at such other address as such Party may stipulate to the other Parties in the manner provided in this Section 11.2.

Partnership Group:

Antero Midstream Partners LP
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Chief Financial Officer
Fax: (303) 357-7315

Company Group (other than the Partnership Group):

Antero Midstream Corporation
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Chief Financial Officer
Fax: (303) 357-7315

Antero:

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Chief Financial Officer
Fax: (303) 357-7315

11.3 ***Severability***. If any provision of this Agreement shall be finally determined to be unenforceable, illegal or unlawful, such provision shall, so long as the economic and legal substance of the transactions contemplated hereby is not affected in any materially adverse manner as to any Party, be deemed severed from this Agreement and the remainder of this Agreement shall remain in full force and effect.

11.4 ***Entire Agreement; Conflicts***. This Agreement, the Second Amended and Restated Services Agreement dated of even date herewith among Antero Partners, General Partner, Antero and the Company (the "***A&R Services Agreement***"), the Water Contribution Agreement, the Prior Contribution Agreement, the Commercial Agreements, any exhibits or schedules to the foregoing and any other transaction documents executed in connection herewith or therewith constitute the entire agreement of the Parties relating to the matters contained herein and therein, superseding all prior contracts or agreements, whether oral or written, relating to the matters contained herein and therein. In the event of a conflict between the terms of this Agreement and the terms of the A&R Services Agreement with respect to the coverage of any individual and/or services provided, the terms of this Agreement shall control.

11.5 ***Amendment or Modification***. This Agreement may be amended or modified from time to time only by the written agreement of all the Parties hereto. Each such instrument shall be reduced to writing and shall be designated on its face an "Amendment" or an "Addendum" to this Agreement.

11.6 ***No Waiver***. Failure of Antero or any member of the Company Group to require performance of any provision of this Agreement shall not affect that Party's right to full performance thereof at any time thereafter, and the waiver by either Antero or any member of the Company Group of a breach of any provision hereof shall not constitute a waiver of any similar breach in the future or of any other breach or nullify the effectiveness of such provision.

11.7 ***Safety Regulations***. All employees of each Party when on the property of the other Party will conform to the rules, regulations and procedures concerning safety of such other Party. From time to time, each Party shall furnish the other Party with complete, accurate and current copies of all such rules, regulations and procedures.

11.8 ***Relationship of Parties***. Nothing hereunder shall be construed as creating any other relationship among the Parties, including but not limited to a partnership, agency or fiduciary relationship, joint venture, limited liability company, association, or any other enterprise.

11.9 ***Governing Law***. Each of the Parties hereby irrevocably consents and agrees that any dispute arising out of or relating to this Agreement or any related document shall exclusively be brought in the courts of the State of Colorado, in Denver County or the federal courts located in the District of Colorado. The Parties agree that, after such a dispute is before a court as specified in this Section 11.9 and during the pendency of such dispute before such court, all actions with respect to such dispute, including any counterclaim, cross-claim or interpleader, shall be subject to the exclusive jurisdiction of such court. The Parties also agree that after such a dispute is before a court as specified in this Section 11.9, and during the pendency of such dispute before such court, each of the Parties hereby waives, and agrees not to assert, as a defense in any legal dispute, that it is not subject thereto or that such dispute may not be brought or is not maintainable in such court or that its property is exempt or immune from execution, that the dispute is brought in an inconvenient forum or that the venue of the dispute is improper. Each Party agrees that a final judgment in any dispute described in this Section 11.9 after the expiration of any period permitted for appeal and subject to any stay during appeal shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by laws.

11.10 ***Further Assurances***. In connection with this Agreement and all transactions contemplated by this Agreement, each Party agrees to execute and deliver such additional documents and instruments and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions and conditions of this Agreement and all such transactions.

11.11 ***Counterparts***. This Agreement may be executed in one or more counterparts, including electronic, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. In the event that any signature is delivered by facsimile transmission or by e-mail delivery of a ".pdf" format data file, such signature shall create a valid and binding obligation of the Party executing (or on whose behalf such signature is executed) with the same force and effect as if such facsimile or ".pdf" signature page were an original thereof.

11.12 ***Rights of Third Parties***. The provisions of this Agreement are enforceable solely by the Parties to this Agreement, and no third party (including any Seconded Employee) shall have the right, separate and apart from the Parties to this Agreement, to enforce any provision of this Agreement or to compel any Party to this Agreement to comply with the terms of this Agreement.

[Signatures on following page]

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first set forth above.

ANTERO MIDSTREAM CORPORATION

By: /s/ Alvyn A. Schopp

Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO MIDSTREAM PARTNERS LP

By: Antero Midstream Partners GP LLC, its general partner

By: /s/ Alvyn A. Schopp

Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO MIDSTREAM PARTNERS GP LLC

By: /s/ Alvyn A. Schopp

Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO MIDSTREAM LLC

By: /s/ Alvyn A. Schopp

Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO WATER LLC

By: /s/ Alvyn A. Schopp

Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO TREATMENT LLC

By: /s/ Alvyn A. Schopp

Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO RESOURCES CORPORATION

By: /s/ Alvyn A. Schopp

Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

Signature Page to Services and Secondment Agreement

SCHEDULE 1

The services shall include the personnel necessary for the provision of comprehensive Operating Services. Antero shall second, or cause to be seconded, Seconded Employees to perform the following Operating Services in connection with the operation and maintenance of the Assets, all in accordance with, and subject to, the requirements of this Agreement:

OPERATING SERVICES: WATER ASSETS

The Seconded Employees shall perform the following Operating Services with respect to the Water Assets:

1. provide, or procure (in the name of Antero Partners or its applicable Affiliate) and manage, those services (including operation, maintenance, engineering and construction services) necessary for the operation of the Water Assets and to maintain the Water Assets in sound operating condition and good repair;
2. perform routine maintenance, preventative maintenance and capitalized repairs;
3. perform corrosion and inspection services;
4. perform or cause to be performed waste water fluid handling services;
5. submit the applications for and in the name of Antero Partners or its applicable Affiliate, pursue the issuance of, and maintain in force, the environmental and all other permits necessary for the operation of the Water Assets;
6. prepare, sign and file, or cause to be prepared, signed and filed, in each case in the name of Antero Partners or its applicable Affiliate, all filings required to be filed by an operator of comparable water transportation and disposal assets with any Governmental Authority with respect to the Water Assets or the operation thereof; and
7. perform or cause to be performed any other services with respect to the Water Assets and associated business reasonably requested by Antero Partners.

OPERATING SERVICES: GATHERING FACILITIES

The Seconded Employees shall perform the following Operating Services with respect to the Gathering Facilities:

1. conduct, or cause to be conducted, all operations with respect to the Gathering Facilities, and shall procure and furnish, or cause to be procured or furnished in the name of Antero Partners or its applicable Affiliate, all materials, equipment, services, supplies, and labor necessary for the operation and maintenance of the Gathering Facilities, engineering support for these activities, and related warehousing and security, including the following:
   i. Maintain and operate flow and pressure control, monitoring, and over-pressure protection;
   ii. Maintain, repair, recondition, overhaul, and replace equipment, as needed, to keep the Gathering Facilities in good working order;
   iii. Operate the Gathering Facilities in a manner consistent with the standard of conduct set forth in the applicable Commercial Agreements; and
   iv. Conduct all other routine day-to-day operations of the Gathering Facilities.
2. provide, manage and conduct, or cause to be provided, managed and conducted, the business operations associated with the Gathering Facilities, including, the following:
   i. Transportation and logistics, including commercial operations;
   ii. Contract administration;
   iii. Gas control;

iv. Gas measurement;

v. GIS mapping;

vi. Database mapping, reporting and maintenance;

vii. Rights of way;

viii. Materials management;

ix. Engineering support (including facility design and optimization); and

x. perform or cause to be performed any other services with respect to the Gathering Facilities and associated business reasonably requested by Antero Partners.

3 . coordinate and direct, or cause to be coordinated and directed, the activities of Persons (including contractors, subcontractors, consultants, professionals, service and other organizations) required to perform the duties and responsibilities necessarily for the provision of the Operating Services. Such persons may include employees of Antero or its Affiliates or employees of one or more third persons; *provided, however*, that any contracts or agreements with respect to third party services shall be entered into in the name of Antero Partners or its applicable Affiliates unless otherwise agreed by Antero Partners in writing.

SCHEDULE 2
ACCOUNTING PROCEDURES

1 . ***Statements and Billings***. Antero shall bill Antero Partners or any other member of the Company Group being provided with Operating Services, as applicable, in accordance with Section 4.2 of this Agreement. If requested by the Company or Antero Partners, Antero will promptly provide reasonably sufficient support for the Expenditures anticipated to be incurred for the following Month. Bills will be summarized by appropriate classifications indicative of the nature thereof and will be accompanied by such detail and supporting documentation as the Company or Antero Partners may reasonably request.

2 . ***Records***. The Parties shall maintain accurate books and records covering all performance of the Services. Antero shall serve as the common paymaster, within the meaning of Section 3121(s) of the Code, for the Company and any other applicable member of the Company Group with respect to the Seconded Employees. In connection therewith, Antero shall accurately record the portion of the cost of wages, salaries, and other compensation paid by Antero to the Seconded Employees that is attributable to the performance of the Operating Services by the Seconded Employees pursuant to this Agreement, including deductions and taxes measured by such wages, salaries and other compensation.

3 . ***Purchase of Materials***. All material, equipment and supplies used or consumed on behalf of the Assets will be owned by Antero Partners or the relevant member of the Company Group, as applicable, and purchased or furnished for its account. So far as is reasonably practical and consistent with efficient, safe and economical operation as determined by Antero, only such material shall be obtained for the Assets as may be required for immediate or near-term use, and the accumulation of surplus stock shall be avoided. To the extent reasonably possible, the Seconded Employees shall take advantage of discounts available by early payments and pass such benefits (or an allocable portion thereof) on to Antero Partners or the relevant member of the Company Group.

4. *Accounting Procedures*.

(a) Antero is part of an affiliated group of companies (the "***Affiliated Group***") that as of the date of this Agreement is engaged in the exploration and production of natural gas. Accounting, purchasing, and risk management functions and services (among other functions and services) as of the date of this Agreement are managed or provided by Antero or one of its Affiliates to the Affiliated Group. The costs and expenses incurred by Antero or such Affiliate in managing or providing such functions and services are accrued on the books and records of Antero in accordance with GAAP and are allocated (where applicable) among the members of the Affiliated Group in accordance with GAAP (such accrual and allocation procedure, the "***Accounting Procedures***").

(b) The costs and expenses incurred by any member of the Company Group in managing or providing accounting, purchasing, and risk management functions and services (among other functions and services) are to be accrued on the books and records of any such member on a basis consistent with the Accounting Procedures.

(c) Antero shall determine and allocate the Expenditures on a basis consistent with the Accounting Procedures and shall provide a mechanism for validating an Expenditure and the allocation of such Expenditure. If Antero Partners and the Company believe that the determination or allocation of any Expenditure is inconsistent with the Accounting Procedures, then Antero Partners and the Company shall notify Antero in writing of the specific manner in which Antero Partners and the Company regard such determination or allocation to be deficient or objectionable. Antero shall either correct or change such determination or allocation in accordance with the notice, or, if Antero disagrees with the notice provided by Antero Partners and the Company, shall reasonably cooperate with Antero Partners and the Company in addressing such correction or change. If Antero Partner's auditors, the Company's auditors or the Audit Committee make reasonable suggestions with respect to the Accounting Procedures or the use of the Accounting Procedures pursuant to the terms of this Agreement, Antero will reasonably cooperate with Antero Partners and the Company and any other applicable member of the Company Group in addressing such suggestions; *provided*, the implementation of such suggestions shall be subject to the mutual agreement of Antero Partners, the Company and Antero.

(d) There shall be no duplication of charges for the same Expenditure. Likewise, no duplication of an Expenditure that has been charged to Antero Partners or any other applicable member of the Company Group under any other agreement between the Parties shall occur.

Exhibit 10.8

Execution Version

SECOND AMENDED AND RESTATED SERVICES AGREEMENT

This SECOND AMENDED AND RESTATED SERVICES AGREEMENT (this "**Agreement**") dated as of December 31, 2019, and effective as of March 13, 2019, is entered into by and among Antero Midstream Partners LP, a Delaware limited partnership (the "**Partnership**"), Antero Midstream Corporation, a Delaware corporation (the "**Company**"), Antero Partners GP LLC, a Delaware limited liability company that is disregarded as separate from the Company for U.S. federal income tax purposes (the "**General Partner**"), and Antero Resources Corporation, a Delaware corporation ("**Antero**"). The Partnership, the Company, the General Partner and Antero may be referred to herein individually as "**Party**" or collectively as "**Parties**."

RECITALS

WHEREAS, each of the Partnership, Antero and Antero Resources Midstream Management LLC, a Delaware limited liability company and predecessor in interest to the General Partner, entered into an Amended and Restated Services Agreement dated September 23, 2015 (the "**First Amended and Restated Services Agreement**"), and the Parties intend to amend and restate such First Amended and Restated Services Agreement in its entirety as set forth herein and add the Company as a Party hereto;

WHEREAS, Antero, Antero Midstream GP LP, a Delaware limited partnership and predecessor in interest to the Company, AMGP GP LLC, a Delaware limited liability company, and Antero IDR Holdings LLC, a Delaware limited liability company, are parties to that certain Services Agreement dated May 9, 2017, and the Parties intend that such agreement be superseded by this Agreement;

WHEREAS, the Company, the Partnership and the other members of the Company Group desire that Antero provide the Services (as defined below); and

WHEREAS, the Parties desire to set forth their respective rights and responsibilities with respect to the provision of the Services.

NOW THEREFORE, in consideration of their mutual undertakings and agreements hereunder, the Parties agree that the First Amended and Restated Services Agreement shall hereby be amended and restated in its entirety as follows:

ARTICLE 1
PERFORMANCE OF SERVICES

1 . 1 Agreement to Provide Services. Antero shall provide, or cause to be provided, the corporate, general and administrative services set forth on Exhibit A and such additional services as the Parties may agree in writing from time to time (collectively, the "**Services**") to the Company, the Partnership and the subsidiaries of the Partnership, and any other subsidiaries of the Company (collectively, the "**Company Group**"). The nature and quality of the Services provided under this Agreement shall be provided in compliance with all applicable law and shall be consistent with the nature and quality of the services of such type that Antero performs in the management of its own business and affairs. If, subsequent to the date hereof, additional services not listed on Exhibit A are needed, Antero shall use commercially reasonable efforts to provide Services Personnel (as

defined below) to provide such services on mutually agreeable pricing and other terms to be determined on a basis similar to the pricing and other terms set forth in this Agreement, whereupon such additional services shall be considered part of the Services.

ARTICLE 2
SERVICES PERSONNEL

2.1 Relationship of the Parties. The Parties acknowledge that the Services shall be performed by such employees of Antero or another member of the Antero Group (as defined in Section 3.1) as the Parties shall agree to from time to time (such employees who perform the Services, the "**Services Personnel**"). The Services Personnel shall be under the direction and control of the Company and any other member of the Company Group to which such Services Personnel provide the Services. To the extent Services are performed for the Partnership or any of its subsidiaries, the Parties acknowledge that the Services Personnel shall report into the management structure of the Partnership, and, accordingly shall be under the direct management, supervision, direction and control of the Company as a result of the Company's control of the General Partner, which controls the Partnership. To the extent that supervisors or managers of the Services Personnel issue instructions to Services Personnel regarding the Services, such supervisors and managers shall be treated for purposes of this Agreement as acting on behalf of the member of the Company Group for which such Services Personnel are providing Services. The employment of the Services Personnel by Antero and the Company shall constitute "concurrent employment" (as defined in Treasury Regulations § 31.3121(s)-1(b)(3)). Subject to the foregoing, nothing hereunder shall be construed as creating any other relationship among the Parties, including but not limited to a partnership, agency or fiduciary relationship, joint venture, limited liability company, association, or any other enterprise.

2.2 Termination of Services Personnel. The Company and the other members of the Company Group shall have no authority to terminate a member of the Services Personnel's employment with Antero; *provided, however*, that the Company and the other members of the Company Group for which the Services Personnel provide Services will have the right to (a) terminate a member of the Services Personnel's employment with such entity and (b) terminate the assignment to it of any member of the Services Personnel for any reason at any time, upon prior written notice to Antero. Antero shall, at all times, have sole authority to terminate a member of the Services Personnel's employment with Antero. Antero retains the right to terminate the assignment of any member of the Services Personnel for any reason at any time or to hire or discharge any member of the Services Personnel with respect to their employment with Antero. Upon the termination of the assignment of any member of the Services Personnel for any reason, such member of the Services Personnel will cease performing services for the Company Group and shall cease to be jointly employed by Antero, the Company and any other member of the Company Group.

2.3 Title to Items Obtained on Behalf of the Company Group. To the extent that any materials, equipment, supplies, consumables, spare parts and other items are purchased or obtained by Antero or its Affiliates for or on behalf of any member of the Company Group, title to such items shall pass immediately to and vest in such member of the Company Group upon passage of title from the vendor or supplier thereof free and clear of all liens or encumbrances arising by, through and under Antero and its Affiliates but not otherwise (other than liens and security interests securing any unpaid portion of the purchase price for the same). All materials, data and documents, to the extent prepared or developed by any Services Personnel during the term of this Agreement for any member of the Company Group or their respective Affiliates in connection with the Services Personnel's performance of the Services, including all manuals, data, designs, drawings, plans, specifications and reports, shall belong to such member of the Company Group or such respective Affiliate. All such materials, documents and data, in whatever form, including electronic copies and databases, shall be provided promptly to such member of the Company Group following any termination of this Agreement, or at such other times as such member of the Company Group may reasonably direct; *provided, however*, that Antero shall be entitled to retain (a) copies of such materials, documents and data for document retention and compliance purposes if required by law, rules, regulations or orders of the court and (b) all electronic copies (if any) of any such materials, documents and data residing in its (and its Affiliates') automatic backup systems.

2 . 4 Workers' Compensation. With respect to the Company Group's operations in Ohio, Antero shall obtain workers' compensation coverage as defined by Ohio Revised Code Chapter 4123 on behalf of Antero and the members of the Company Group for which the Services Personnel are providing the Services, and each such member of the Company Group shall be considered an employer solely for the purposes of Ohio Revised Code Chapter 4123. With respect to the Company Group's operations in West Virginia, Antero shall obtain workers' compensation coverage as defined by West Virginia Code Chapter 23 on behalf of Antero and the members of the Company Group for which the Services Personnel are providing the Services, and each such members of the Company Group shall be considered a special employer solely for the purposes of West Virginia Code Chapter 23. With respect to the Company Group's operations in Pennsylvania, Antero shall obtain workers' compensation coverage as defined by Pennsylvania Statutes Title 77 on behalf of Antero and the members of the Company Group for which the Services Personnel are providing the Services, and the Company and each such members of the Company Group shall be considered a statutory employer solely for the purposes of Pennsylvania Statutes Title 77 § 481. With respect to the Company Group's operations in Colorado, Antero shall obtain workers' compensation coverage as defined by Colorado Revised Statutes Title 8 on behalf of Antero and the members of the Company Group for which the Services Personnel are providing the Services, and the Company and each such members of the Company Group shall be considered a statutory employer solely for the purposes of Colorado Revised Statutes Title 8, Articles 40 to 47. For the avoidance of doubt, nothing in this Agreement has any effect on the right of a Services Personnel to prosecute a workers' compensation claim against Antero or any member of the Company Group for which such Services Personnel is providing the Services.

2.5 Benefits Plans. Neither the Company, the Partnership nor any other member of the Company Group for which the Services Personnel are providing Services shall be a participating employer in any benefit plan of Antero or any of its Affiliates. Antero shall remain solely responsible for all obligations and liabilities arising with respect to any benefit plans related to any Services Personnel, and the Company Group shall not assume any benefit plan or have any obligations or liabilities arising thereunder, in each case except for costs properly chargeable to the Company Group under this Agreement.

2.6 Notice. At the request of the Company, the Partnership or another member of the Company Group, Antero shall notify each member of the Services Personnel of such employee's assignment to provide Services to the applicable members of the Company Group. The notice of such assignment provided to each member of the Services Personnel may state that (a) such member of the Services Personnel will be a joint employee of Antero, the Company and any other member of the Company Group for which such member of the Services Personnel is providing Services, and (b) for any workplace injury, the member of the Services Personnel's sole remedy against either Antero, the Company, any other member of the Company Group, and each of their respective Affiliates will be under the workers' compensation insurance policy or qualified self-insured program of Antero. For the avoidance of doubt, the Parties acknowledge that the Services Personnel will, during the period of their assignment to provide Services, be called upon to perform services for both the members of the Company Group and Antero (and their respective applicable Affiliates) of the same or closely-related nature.

ARTICLE 3
REIMBURSEMENT AND BILLING PROCEDURES

3 . 1 Reimbursement. Subject to and in accordance with the terms and provisions of this Article 3 (but without duplication of any amounts due pursuant to the Secondment Agreement dated as of even date herewith among the Company, the Partnership, the General Partner and the other parties thereto) and taking into account reasonable allocation and other procedures as may be agreed upon from time to time by the Parties, the Company shall reimburse Antero for all direct and indirect costs and expenses incurred by Antero and its Affiliates (collectively, the "**Antero Group**") in connection with the provision of the Services to the Company and any other member of the Company Group (other than the Partnership and any subsidiary of the Partnership, and the Partnership shall reimburse Antero for all direct and indirect costs and expenses incurred by the Antero Group in connection with the provision of the Services to the Partnership and the subsidiaries of the Partnership. Such reimbursement shall include reimbursement for the following:

(a) costs, expenses and expenditures incurred in the performance of the Services; *provided, however*, Antero shall not be reimbursed for such costs, expenses and expenditures for which Antero is required to provide indemnification to the Company or the Partnership or any other Company Indemnitee pursuant to Section 5.3;

(b) salaries, wages and other compensation and employment benefits and expenses of the Services Personnel (including any payroll taxes), plus general and administrative expenses to the extent associated with the Services Personnel (including the cost of workers' compensation insurance coverage with respect to such periods that the Services Personnel are providing the Services);

(c) any payments or expenses incurred for insurance coverage, including allocable portions of premiums, and negotiated instruments (including surety bonds and performance bonds) provided by underwriters with respect to the assets or the business of the Company Group;

(d) any taxes or other direct operating expenses paid by the Antero Group for the benefit of the Company Group (including any state income, franchise, property, sales or similar tax paid by the Antero Group resulting from the inclusion of any member of the Company Group in a combined or consolidated state income, franchise, property, sales or similar tax report with Antero as required by applicable law); *provided, however*, that the amount of any such reimbursement shall be limited to the tax that such member of the Company Group would have paid had it not been included in a combined or consolidated group with Antero; and

(e) all expenses and expenditures incurred by the Company as a result of being a publicly traded entity or by the Partnership as a result of being a publicly traded entity prior to the closing of the Simplification Transactions, including, but not limited, to costs associated with annual and quarterly reports, independent auditor fees, governance and compliance, registrar and transfer agent fees, tax return preparation and related services, legal fees and independent director compensation;

it being agreed, however, that to the extent any reimbursable costs or expenses incurred by the Antero Group consist of an allocated portion of costs and expenses incurred by the Antero Group for the benefit of both the Company Group and the other members of the Antero Group, such allocation shall be made on a reasonable cost reimbursement basis as determined by Antero in good faith.

For purposes of this Agreement, "**Affiliate**" means (A) with respect to Antero, any other Person that directly or indirectly through one or more intermediaries is controlled by Antero, excluding the Company, the General Partner and any other Person that directly or indirectly through one or more intermediaries is controlled by the General Partner (including the Partnership and its subsidiaries); and (B) with respect to the Company, the Partnership, the General Partner and any other Person that directly or indirectly through one or more intermediaries is controlled by the General Partner. As used herein, the term "**control**" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise, and the term "**Person**" means any natural person, corporation, limited liability company, partnership, joint venture, trust, unincorporated organization, association, joint stock company or governmental authority. For purposes of this Agreement, "**Simplification Transactions**" means the transactions consummated pursuant to that certain Simplification Agreement by and among Antero Midstream GP LP, the Partnership and the other parties thereto dated October 9, 2018.

3.2 Billing Procedures. The Company shall pay or cause to be paid to Antero or any other member of the Antero Group providing the Services, as applicable (each a "**Service Provider**"), for billed costs and expenses no later than the later of (a) the last day of the month following the performance month or (b) thirty (30) business days following the date of the Service Provider's billing of such costs and expenses. Payments made under this Agreement shall be made in cash, by wire transfer or by offset to other amounts due and owing from one Party to another; *provided, however*, that any offset shall be documented and such documentation shall be provided to the relevant Party upon request. The Company and the Partnership shall have the right to review all source documentation concerning the liabilities, costs and expenses allocated to the Company, the Partnership and any other members of the Company Group upon reasonable notice and during regular business hours.

ARTICLE 4
TERM AND TERMINATION

4.1 Term. Unless terminated earlier, this Agreement shall continue in effect until the twentieth (20th) anniversary of the execution of the Initial Services Agreement and from year to year thereafter (with the initial term of this Agreement deemed extended for each of any such additional year) until such time as this Agreement is terminated. Any termination of this Agreement during any such year to year extension of the initial term shall be effected by written notice of such termination in accordance with Section 4.2 on or before the one hundred eightieth (180th) day prior to the next anniversary of the execution of the Initial Services Agreement with such termination effective upon the occurrence of such next anniversary.

For purposes of this Agreement, "**Initial Services Agreement**" means the Services Agreement dated November 10, 2014, by and among Antero, Antero Partners and Antero Resources Midstream Management LLC.

4.2 Termination.

(a) Methods of Termination. Notwithstanding anything to the contrary in this Agreement, this Agreement may be terminated at any time (i) in its entirety by mutual written agreement of all of the Parties to the Agreement, (ii) with respect to the Services received by the Company, by the Company, in its sole discretion, effective upon delivery of written notice of such termination to Antero and (iii) with respect to the Services received by the Partnership, by the Partnership, in its sole discretion, effective upon delivery of written notice of such termination to Antero.

(b) Effect of Termination. Upon termination of this Agreement, all rights and obligations of the Parties under this Agreement shall terminate, *provided*, *however*, that such termination shall not affect or excuse the performance of any Party under the provisions of Article 5 which provisions shall survive the termination of this Agreement indefinitely, or the obligations under Article 3 with respect to amounts relating to periods prior to the termination of this Agreement, which provisions shall survive until such amounts are paid in full.

ARTICLE 5
INDEMNITY

5.1 Indemnification Scope. IT IS IN THE BEST INTERESTS OF THE PARTIES THAT CERTAIN RISKS RELATING TO THE MATTERS GOVERNED BY THIS AGREEMENT SHOULD BE IDENTIFIED AND ALLOCATED AS BETWEEN THEM. IT IS THEREFORE THE INTENT AND PURPOSE OF THIS AGREEMENT TO PROVIDE FOR THE INDEMNITIES SET FORTH HEREIN TO THE MAXIMUM EXTENT ALLOWED BY LAW. ALL PROVISIONS OF THIS ARTICLE SHALL BE DEEMED CONSPICUOUS WHETHER OR NOT CAPITALIZED OR OTHERWISE EMPHASIZED.

5.2 Indemnified Persons. Wherever "the Company" or "Antero" appears as an indemnitee in this Article, the term shall include that entity and its Affiliates, and the respective agents, officers, directors, employees, representatives and contractors and subcontractors of any tier of the foregoing entities involved in actions or duties to act on behalf of the indemnified Party.

These groups will be the "**Company Indemnitees**" or the "**Antero Indemnitees**", as applicable, *provided*, *however*, that for the avoidance of doubt, the Company Indemnitees shall not include Antero and its Affiliates, and the Antero Indemnitees shall not include the Company, the Partnership, any subsidiary of the Partnership or the General Partner. "Third parties" shall not include any Partnership Indemnitees or Antero Indemnitees.

5.3 Indemnifications.

(a) EXCEPT AS OTHERWISE PROVIDED IN THE SECONDMENT AGREEMENT, THE COMPANY AND THE PARTNERSHIP SHALL RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS THE ANTERO INDEMNITEES FROM AND AGAINST ANY AND ALL CLAIMS, CAUSES OF ACTION, DEMANDS, LIABILITIES, LOSSES, DAMAGES, FINES, PENALTIES, JUDGMENTS, EXPENSES AND COSTS, INCLUDING REASONABLE ATTORNEYS' FEES AND COSTS OF INVESTIGATION AND DEFENSE (EACH, A " **LIABILITY**") (INCLUDING, WITHOUT LIMITATION, ANY LIABILITY FOR (1) DAMAGE, LOSS OR DESTRUCTION OF THE ASSETS OR THE BUSINESS OF THE COMPANY GROUP, (2) BODILY INJURY, ILLNESS OR DEATH OF ANY PERSON, AND (3) LOSS OF OR DAMAGE TO EQUIPMENT OR PROPERTY OF ANY PERSON) ARISING FROM OR RELATING TO THE COMPANY'S, THE PARTNERSHIP'S, THE GENERAL PARTNER'S OR ANTERO'S PERFORMANCE OF THIS AGREEMENT, EXCEPT TO THE EXTENT SUCH LIABILITY IS CAUSED BY THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE ANTERO INDEMNITEES.

(b) EXCEPT AS OTHERWISE PROVIDED IN THE SECONDMENT AGREEMENT, ANTERO SHALL RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS THE COMPANY INDEMNITEES FROM AND AGAINST ANY AND ALL LIABILITIES (INCLUDING, WITHOUT LIMITATION, ANY LIABILITY FOR (1) DAMAGE, LOSS OR DESTRUCTION OF THE ASSETS OR THE BUSINESS OF THE COMPANY GROUP, (2) BODILY INJURY, ILLNESS OR DEATH OF ANY PERSON AND (3) LOSS OF OR DAMAGE TO EQUIPMENT OR PROPERTY OF ANY PERSON) ARISING FROM OR RELATING TO ANTERO'S PERFORMANCE UNDER THIS AGREEMENT TO THE EXTENT SUCH LIABILITY IS CAUSED BY THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE COMPANY INDEMNITEES.

5.4 Damages Limitations. Any and all damages recovered by any Party pursuant to this Article 5 or pursuant to any other provision of or actions or omissions under this Agreement shall be limited to actual damages. CONSEQUENTIAL DAMAGES AND EXEMPLARY AND PUNITIVE DAMAGES SHALL NOT BE RECOVERABLE UNDER ANY CIRCUMSTANCES EXCEPT TO THE EXTENT THOSE DAMAGES ARE INCLUDED IN THIRD PARTY CLAIMS FOR WHICH A PARTY HAS AGREED HEREIN TO INDEMNIFY THE OTHER PARTY. EACH PARTY ACKNOWLEDGES IT IS AWARE THAT IT HAS POTENTIALLY VARIABLE LEGAL RIGHTS UNDER COMMON LAW AND BY STATUTE TO RECOVER CONSEQUENTIAL, EXEMPLARY, AND PUNITIVE DAMAGES UNDER CERTAIN CIRCUMSTANCES, AND, EXCEPT AS PROVIDED IN THE PRECEDING SENTENCE WITH RESPECT TO THIRD PARTY CLAIMS, EACH PARTY NEVERTHELESS WAIVES, RELEASES, RELINQUISHES, AND SURRENDERS RIGHTS TO CONSEQUENTIAL PUNITIVE AND EXEMPLARY DAMAGES TO THE FULLEST EXTENT PERMITTED BY

LAW WITH FULL KNOWLEDGE AND AWARENESS OF THE CONSEQUENCES OF THE WAIVER REGARDLESS OF THE NEGLIGENCE OR FAULT OF EITHER PARTY.

5.5 Defense of Claims. The indemnifying Party shall defend, at its sole expense, any claim, demand, loss, liability, damage or other cause of action within the scope of the indemnifying Party's indemnification obligations under this Agreement, *provided* that the indemnified Party notifies the indemnifying Party promptly in writing of any claim, loss, liability, damage or cause of action against the indemnified Party and gives the indemnifying Party information and assistance at the reasonable expense of the indemnifying Party in defense of the matter. The indemnified Party may be represented by its own counsel (at the indemnified Party's sole expense) and may participate in any proceeding relating to a claim, loss, liability, damage or cause of action in which the indemnified Party or the indemnifying Party are defendants, *provided*, *however*, the indemnifying Party shall, at all times, control the defense and any appeal or settlement of any matter for which it has indemnification obligations under this Agreement so long as any such settlement includes an unconditional release of the indemnified Party from all liability arising out of such claim, demand, loss, liability, damage or other cause of action and does not require any remediation or other action other than the payment of money, which the indemnifying party will be responsible for hereunder, and does not include a statement as to or an admission of fault, culpability or a failure to act by or on behalf of the indemnified Party. Should the Parties both be named as defendants in any third-party claim or cause of action arising out of or relating to the Services, the Parties will cooperate with each other in the joint defense of their common interests to the extent permitted by law, and will enter into an agreement for joint defense of the action if the Parties mutually agree that the execution of the same would be beneficial.

ARTICLE 6
NOTICES

A Party may give notices to any other Party by first class mail postage prepaid, by overnight delivery service, or by facsimile with receipt confirmed at the following addresses or other addresses furnished by a Party by written notice.

If to the Company or to the General Partner:

Antero Midstream Corporation
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Chief Financial Officer
Fax: (303) 357-7315

If to the Partnership or the subsidiaries of the Partnership to:

Antero Midstream Partners LP
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Chief Financial Officer
Fax: (303) 357-7315

If to Antero to:

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202
Attn: Chief Financial Officer
Fax: (303) 357-7315

ARTICLE 7
GENERAL

7 . 1 Succession and Assignment. This Agreement shall be binding upon and inure to the benefit of the Parties named herein. No Party may assign or otherwise transfer either this Agreement or any of its rights, interests or obligations hereunder without the prior written approval of the other Parties, which approval shall not be unreasonably withheld, conditioned or delayed.

7.2 Governing Law. This Agreement will be governed by and construed and enforced in accordance with the laws of the State of Colorado, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

7.3 Consent to Jurisdiction, Etc.; Waiver of Jury Trial. Each of the Parties hereby irrevocably consents and agrees that any dispute arising out of or relating to this Agreement or any related document shall exclusively be brought in the courts of the State of Colorado, in Denver County or the federal courts located in the District of Colorado. The Parties agree that, after such a dispute is before a court as specified in this Section 7.3 and during the pendency of such dispute before such court, all actions with respect to such dispute, including any counterclaim, cross-claim or interpleader, shall be subject to the exclusive jurisdiction of such court. The Parties also agree that after such a dispute is before a court as specified in this Section 7.3, and during the pendency of such dispute before such court, each of the Parties hereby waives, and agrees not to assert, as a defense in any legal dispute, that it is not subject thereto or that such dispute may not be brought or is not maintainable in such court or that its property is exempt or immune from execution, that the dispute is brought in an inconvenient forum or that the venue of the dispute is improper. Each Party agrees that a final judgment in any dispute described in this Section 7.3 after the expiration of any period permitted for appeal and subject to any stay during appeal shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by laws. THE PARTIES HEREBY WAIVE IRREVOCABLY ANY AND ALL RIGHTS TO DEMAND A TRIAL BY JURY IN CONNECTION WITH THIS AGREEMENT, THE TRANSACTIONS CONTEMPLATED HEREBY OR ANY DOCUMENT CONTEMPLATED HEREIN OR OTHERWISE RELATED HERETO.

7.4 Non-waiver of Future Default. No waiver of any Party of any one or more defaults by another in performance of any of the provisions of this Agreement shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

7 . 5 Audit and Maintenance of Records; Reporting. The Company and the Partnership shall have the right to review and contest the expenses charged pursuant to the terms of this Agreement in accordance with this Section 7.5. The Company and the Partnership, as applicable, shall have the right, upon reasonable notice and at reasonable times, to inspect and audit all the

records, books, reports, data and processes related to the Services performed by Antero to ensure Antero's compliance with the terms of this Agreement. If any such examination establishes an inaccuracy, necessary adjustments will be made promptly. If any information provided to or reviewed by the Company, the Partnership or their respective representatives pursuant to this Section 7.5 is confidential, the Parties and the respective representatives shall execute a mutually acceptable confidentiality agreement prior to such inspection or audit.

7.6 Entire Agreement; Amendments and Schedules. This Agreement shall be amended or waived only by an instrument in writing executed by the Parties. This Agreement, the Secondment Agreement, the Water Contribution Agreement (as defined in the Secondment Agreement), the Prior Contribution Agreement (as defined in the Secondment Agreement), the Commercial Agreements (as defined in the Secondment Agreement), any exhibits or schedules to the foregoing and any other transaction documents executed in connection herewith or therewith shall constitute the entire agreement of the Parties relating to the matters contained herein and therein, superseding all prior contracts or agreements, whether oral or written, relating to the matters contained herein and therein. In the event of a conflict between the terms of this Agreement and the terms of the Secondment Agreement with respect to the coverage of any individual and/or services provided, the Secondment Agreement shall control.

7.7 Force Majeure.

(a) If any Party is rendered unable, wholly or in part, by force majeure to carry out its obligations under this Agreement, other than to make payments due, the obligations of that Party, so far as they are affected by force majeure, will be suspended during the continuance of any inability so caused, but for no longer period. The Party whose performance is affected by force majeure will provide notice to each other Party, which notice may initially be oral, followed by a written notification, and will use commercially reasonable efforts to resolve the event of force majeure to the extent reasonably possible.

(b) "**Force majeure**" as used in this Agreement shall mean any cause or causes not reasonably within the control of the Party claiming suspension and which, by the exercise of reasonable diligence, such Party is unable to prevent or overcome, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, acts of terror, sabotage, wars, blockades, military action, insurrections, riots, epidemics, landslides, subsidence, lightning, earthquakes, fires, storms or storm warnings, crevasses, floods, washouts, civil disturbances, explosions, breakage or accidents to wells, machinery, equipment or lines of pipe; freezing of wells, equipment on lines of pipe; the necessity for testing or making repairs or alterations to wells, machinery, equipment or lines of pipe, freezing of wells, equipment or lines of pipe; inability of any Party hereto to obtain, after the exercise of reasonable diligence, necessary materials, supplies or governmental approvals, and action or restraint by any governmental authority (so long as the Party claiming suspension has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such action or restraint, and as long as such action or restraint is not the result of a failure by the claiming Party to comply with any applicable law). The settlement of strikes or lockouts will be entirely within the discretion of the Party having the difficulty, and settlement of strikes, lockouts, or other labor disturbances when that course is considered inadvisable is not required.

7.8 Counterpart Execution. This Agreement may be executed in one or more counterparts, including electronic, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. In the event that any signature is delivered by facsimile transmission or by e-mail delivery of a ".pdf" format data file, such signature shall create a valid and binding obligation of the Party executing (or on whose behalf such signature is executed) with the same force and effect as if such facsimile or ".pdf" signature page were an original thereof.

7.9 Third Parties. The provisions of this Agreement are enforceable solely by the Parties to this Agreement, and no third party (including, without limitation, any Limited Partner of the Partnership or the Services Personnel) shall have the right, separate and apart from the Parties to this Agreement, to enforce any provision of this Agreement or to compel any Party to this Agreement to comply with the terms of this Agreement.

7.10 Severability. If any provision of this Agreement shall be finally determined to be unenforceable, illegal or unlawful, such provision shall, so long as the economic and legal substance of the transactions contemplated hereby is not affected in any materially adverse manner as to any Party, be deemed severed from this Agreement and the remainder of this Agreement shall remain in full force and effect.

7.11 Further Assurances. In connection with this Agreement and all transactions contemplated by this Agreement, each signatory party hereto agrees to execute and deliver such additional documents and instruments and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions and conditions of this Agreement and all such transactions.

The Parties have caused this Agreement to be signed by their duly authorized representatives effective as of the date first written above.

ANTERO RESOURCES CORPORATION

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO MIDSTREAM CORPORATION

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO MIDSTREAM PARTNERS LP

By: Antero Midstream Partners GP LLC, its general partner

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

ANTERO MIDSTREAM PARTNERS GP LLC

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

Exhibit A
Services

1) Financial and administrative services (including, but not limited to, treasury, accounting, internal and external financial reporting, billing, corporate record keeping, cash management and banking, planning, budgeting, internal audit, risk management, financial planning and analysis, and other administrative functions)

2) Real property/land, engineering and geology/geophysics services

3) Environmental, health and safety services (including, but not limited to, permit filing and support for permit filing)

4) Information technology, telephone, office support and other technology services

5) Legal services

6) Human resources services

7) Payroll (including serving as common paymaster, within the meaning of Section 3121(s) of the Internal Revenue Code of 1986, for the Company)

8) Business development services

9) Investor relations, regulatory compliance and governmental relations

10) Tax services (including in its capacity as common paymaster, within the meaning of Section 3121(s) of the Internal Revenue Code of 1986, for the Company, (a) paying and delivering to the appropriate U.S. federal, state and local taxing authorities all payroll and income taxes withheld from, or payable with respect to, the compensation of the Services Personnel and (b) filing all information returns required under applicable law)

11) Insurance administration and claims reporting

12) Such other corporate, general and administrative services as may be agreed upon by the Parties from time to time

LENDER CERTIFICATE

October 29, 2019

To: JPMORGAN CHASE BANK, N.A.,
as Administrative Agent

Antero Resources Corporation (the "Borrower"), certain Subsidiaries of Borrower, as Guarantors, the lenders from time to time party thereto (the "Lenders") and JPMorgan Chase Bank, N.A., as administrative agent for the Lenders (in such capacity, the "Administrative Agent") have entered into that certain Fifth Amended and Restated Credit Agreement, dated as of October 26, 2017 (as the same has been and may further be amended, restated, amended and restated, supplemented or otherwise modified from time to time, the "Credit Agreement"). Unless otherwise defined herein, capitalized terms used herein have the meaning specified in the Credit Agreement.

Please be advised that the undersigned has agreed (a) to become a Lender under the Credit Agreement effective October 29, 2019 (the "Effective Date") with a Commitment of $140,000,000 and (b) that, from and after the Effective Date, it shall be deemed to be a Lender in all respects under the Credit Agreement and the other Loan Documents and shall be bound thereby.

Very truly yours,

ROYAL BANK OF CANADA

By: /s/ Katy Berkemeyer
Name: Katy Berkemeyer
Title: Authorized Signatory

Accepted and Agreed:

JPMORGAN CHASE BANK, N.A.,
as Administrative Agent

By: /s/ David Morris
Name: David Morris
Title: Authorized Officer

Accepted and Agreed:

ANTERO RESOURCES CORPORATION

By: /s/ Michael Kennedy
Name: Michael Kennedy
Title: Senior Vice President – Finance

SCHEDULE 1.01

Applicable Percentages and Commitments

Lender	Commitment	Applicable Percentage
JPMorgan Chase Bank, N.A.	$160,000,000.00	6.06060606061%
Wells Fargo Bank, N.A.	$160,000,000.00	6.06060606061%
Bank of America, N.A.	$140,000,000.00	5.30303030303%
Barclays Bank PLC	$140,000,000.00	5.30303030303%
BMO Harris Bank N.A.	$140,000,000.00	5.30303030303%
Capital One, National Association	$140,000,000.00	5.30303030303%
Citibank, N.A.	$140,000,000.00	5.30303030303%
Credit Agricole Corporate and Investment Bank	$140,000,000.00	5.30303030303%
Royal Bank of Canada	$140,000,000.00	5.30303030303%
ABN Amro Capital USA LLC	$95,000,000.00	3.59848484848%
The Bank of Nova Scotia	$95,000,000.00	3.59848484848%
Compass Bank	$95,000,000.00	3.59848484848%
Canadian Imperial Bank of Commerce, New York Branch	$95,000,000.00	3.59848484848%
Credit Suisse AG, Cayman Islands Branch	$95,000,000.00	3.59848484848%
DNB Capital LLC	$95,000,000.00	3.59848484848%
ING Capital LLC	$95,000,000.00	3.59848484848%
Natixis, New York Branch	$95,000,000.00	3.59848484848%
Sumitomo Mitsui Banking Corporation	$95,000,000.00	3.59848484848%
Toronto Dominion (New York) LLC	$95,000,000.00	3.59848484848%
Branch Banking & Trust Company	$65,000,000.00	2.46212121212%
Comerica Bank	$65,000,000.00	2.46212121212%
Morgan Stanley Bank, N.A.	$65,000,000.00	2.46212121212%
PNC Bank National Association	$65,000,000.00	2.46212121212%
Suntrust Bank	$65,000,000.00	2.46212121212%
U.S. Bank National Association	$65,000,000.00	2.46212121212%
TOTAL	$2,640,000,000.00	100.00000000000%

Antero Lender Certificate – Signature Page

Exhibit 10.13

EXECUTION VERSION

SECOND AMENDMENT TO FIFTH AMENDED AND RESTATED CREDIT AGREEMENT

This SECOND AMENDMENT TO FIFTH AMENDED AND RESTATED CREDIT AGREEMENT (this "Amendment") is made as of December 20, 2019, by and among ANTERO RESOURCES CORPORATION, a Delaware corporation (the "Borrower"), CERTAIN SUBSIDIARIES OF BORROWER, as Guarantors, the LENDERS party hereto, and JPMORGAN CHASE BANK, N.A., as Administrative Agent (in such capacity, the "Administrative Agent"). Unless otherwise expressly defined herein, capitalized terms used but not defined in this Amendment have the meanings assigned to such terms in the Credit Agreement (as defined below).

WITNESSETH:

WHEREAS, Borrower, the Guarantors, the Administrative Agent and the Lenders have entered into that certain Fifth Amended and Restated Credit Agreement, dated as of October 26, 2017 (as the same has been amended, restated, amended and restated, supplemented or otherwise modified from time to time prior to the date hereof, the "Existing Agreement" and as further amended by this Amendment, the "Credit Agreement"); and

WHEREAS, Borrower has requested that Administrative Agent and the Lenders enter into this Amendment to amend certain terms of the Existing Agreement as set forth herein; and

WHEREAS, Administrative Agent, the Lenders, Borrower and Guarantors desire to amend the Existing Agreement as provided herein upon the terms and conditions set forth herein.

NOW, THEREFORE, for and in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and confessed, Borrower, the Guarantors, the Administrative Agent and the Majority Lenders hereby agree as follows:

SECTION 1. Amendments to Credit Agreement. Subject to the satisfaction or waiver in writing of each condition precedent set forth in Section 2 of this Amendment, and in reliance on the representations, warranties, covenants and agreements contained in this Amendment, the Existing Agreement shall be amended, effective as of the Second Amendment Effective Date, in the manner provided in this Section 1.

1.1 Indebtedness. Section 7.01 of the Credit Agreement is hereby amended as follows: (i) Section 7.01(g) is hereby amended by deleting the word "and" at the end of such section, (ii) Section 7.01(h) is hereby re-lettered as a new Section 7.01(i), and (iii) a new Section 7.01(h) of the Credit Agreement is hereby added in its entirety to read as follows:

> *(h) Indebtedness in respect of performance bonds, bid bonds, appeal bonds, surety bonds and completion guarantees and similar obligations not in connection with money borrowed, in each case provided in the ordinary course of business or consistent with past practice, including those incurred to secure health, safety and environmental obligations in the ordinary course of business or consistent with past practice; and*

SECTION 2. Conditions to Effectiveness. This Amendment shall be effective upon the date each of the conditions set forth in this Section 2 is satisfied (the "Second Amendment Effective Date")

2.1 Execution and Delivery. Each Credit Party, at least the Majority Lenders and the Administrative Agent shall have executed and delivered this Amendment.

2.2 Certificates. The Administrative Agent shall have received such documents and certificates as the Administrative Agent or its counsel may reasonably request relating to the organization, existence and good standing of each Credit Party, the authorization of this Amendment and the transactions contemplated hereby and any other legal matters relating to the Credit Parties, this Amendment or the transactions contemplated hereby, all in form and substance reasonably satisfactory to the Administrative Agent and its counsel.

2.3 Other Documents. The Administrative Agent shall have received such other instruments and documents incidental and appropriate to the transactions provided for herein as the Administrative Agent or its special counsel may reasonably request, and all such documents shall be in form and substance reasonably satisfactory to the Administrative Agent.

2.4 Representations and Warranties. Each of the representations and warranties contained in the Credit Agreement and in each of the other Loan Documents shall be true and correct in all material respects on and as of the Second Amendment Effective Date (except to the extent such representations and warranties relate solely to an earlier date, in which case such representations and warranties shall have been true and correct in all material respects as of such date and any representation or warranty which is qualified by reference to "materiality" or "Material Adverse Effect" is true and correct in all respects).

2.5 No Default. No Default shall have occurred and be continuing as of the Second Amendment Effective Date.

2.6 Fees. The Borrower shall have paid all fees, charges and disbursements of counsel to the Administrative Agent (directly to such counsel if requested by the Administrative Agent) to the extent invoiced prior to or on the Second Amendment Effective Date.

SECTION 3. Representations and Warranties of Credit Parties. To induce the Lenders to enter into this Amendment, each Credit Party hereby represents and warrants to the Lenders as follows:

3.1 Reaffirmation of Representations and Warranties/Further Assurances. Both before and after giving effect to the amendments herein, each representation and warranty of such Credit Party contained in the Credit Agreement and in each of the other Loan Documents is true and correct in all material respects as of the date hereof (except to the extent such representations and warranties relate solely to an earlier date, in which case such representations and warranties shall have been true and correct in all material respects as of such date and any representation or warranty which is qualified by reference to "materiality" or "Material Adverse Effect" is true and correct in all respects).

3.2 Corporate Authority; No Conflicts. The execution, delivery and performance by each Credit Party of this Amendment are within such Credit Party's corporate or other organizational powers, have been duly authorized by necessary action, require no action by or in respect of, or filing with, any Governmental Authority and do not violate or constitute a default under any provision of any applicable law or other agreements binding upon any Credit Party or result in the creation or imposition of any Lien upon any of the assets of any Credit Party except for Permitted Liens and otherwise as permitted in the Credit Agreement.

3.3 Enforceability. This Amendment constitutes the valid and binding obligation of Borrower and each other Credit Party enforceable in accordance with its terms, except as (i) the enforceability thereof may be limited by bankruptcy, insolvency or similar laws affecting creditor's rights generally, and (ii) the availability of equitable remedies may be limited by equitable principles of general application.

3.4 No Default. As of the date hereof, both before and immediately after giving effect to this Amendment, no Default has occurred and is continuing.

SECTION 4. Miscellaneous.

4.1 Reaffirmation of Loan Documents and Liens. Any and all of the terms and provisions of the Credit Agreement and the Loan Documents shall, except as amended and modified hereby, remain in full force and effect and are hereby in all respects ratified and confirmed by each Credit Party. Borrower and each Guarantor hereby agrees that the amendments and modifications herein contained shall in no manner affect or impair the liabilities, duties and obligations of any Credit Party under the Credit Agreement and the other Loan Documents or the Liens securing the payment and performance thereof.

4.2 Parties in Interest. All of the terms and provisions of this Amendment shall bind and inure to the benefit of the parties hereto and their respective successors and assigns.

4.3 Legal Expenses. Each Credit Party hereby agrees to pay all reasonable fees and expenses of special counsel to the Administrative Agent incurred by the Administrative Agent in connection with the preparation, negotiation and execution of this Amendment and all related documents.

4.4 Counterparts. This Amendment may be executed in one or more counterparts and by different parties hereto in separate counterparts each of which when so executed and delivered shall be deemed an original, but all such counterparts together shall constitute but one and the same instrument; signature pages may be detached from multiple separate counterparts and attached to a single counterpart so that all signature pages are physically attached to the same document. Delivery of photocopies of the signature pages to this Amendment by facsimile or electronic mail shall be effective as delivery of manually executed counterparts of this Amendment.

4.5 Complete Agreement. THIS AMENDMENT, THE CREDIT AGREEMENT, AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

4.6 Headings. The headings, captions and arrangements used in this Amendment are, unless specified otherwise, for convenience only and shall not be deemed to limit, amplify or modify the terms of this Amendment, nor affect the meaning thereof.

4.7 Governing Law. This Amendment shall be construed in accordance with and governed by the laws of the State of New York.

4.8 Reference to and Effect on the Loan Documents.

(a) This Amendment shall be deemed to constitute a Loan Document for all purposes and in all respects. Each reference in the Existing Agreement to "this Agreement," "hereunder," "hereof," "herein" or words of like import, and each reference in the Existing Agreement or in any other Loan Document, or other agreements, documents or other instruments executed and delivered pursuant to the

Existing Agreement to the "Credit Agreement", shall mean and be a reference to the Existing Agreement as amended by this Amendment.

(b) The execution, delivery and effectiveness of this Amendment shall not operate as a waiver of any right, power or remedy of any Lender or Administrative Agent under any of the Loan Documents, nor constitute a waiver of any provision of any of the Loan Documents.

[*Signature pages follow.*]

IN WITNESS WHEREOF, the parties have caused this Amendment to be duly executed by their respective authorized officers to be effective as of the date first above written.

BORROWER:

ANTERO RESOURCES CORPORATION

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

GUARANTOR:

ANTERO SUBSIDIARY HOLDINGS LLC
MONROE PIPELINE LLC

By: /s/ Alvyn A. Schopp
Name: Alvyn A. Schopp
Title: Chief Administrative Officer, Regional Senior Vice President and Treasurer

JPMORGAN CHASE BANK, N.A.,
as Administrative Agent, Issuing Bank and a Lender

By: /s/ David Morris
Name: David Morris
Title: Authorized Officer

WELLS FARGO BANK, N.A.,
as Issuing Bank and a Lender

By: /s/ Jonathan Herrick
Name: Jonathan Herrick
Title: Director

BARCLAYS BANK PLC,
as a Lender

By: /s/ Jake Lam
Name: Jake Lam
Title: Assistant Vice President

BMO HARRIS BANK N.A.,
as a Lender

By: /s/ Melissa Guzmann
Name: Melissa Guzmann
Title: Director

CAPITAL ONE, NATIONAL ASSOCIATION,
as a Lender

By: /s/ Monica Pantea
Name: Monica Pantea
Title: Vice President

CITIBANK, N.A.,
as a Lender

By: /s/ Michael Zeller
Name: Michael Zeller
Title: Vice President

CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK,
as a Lender

By: /s/ Michael Willis
Name: Michael Willis
Title: Managing Director

By: /s/ Joseph Cariello
Name: Joseph Cariello
Title: Director

THE BANK OF NOVA SCOTIA, HOUSTON BRANCH
as a Lender

By: /s/ Marc Graham
Name: Marc Graham
Title: Managing Director and Co-Head US Corporate Banking Energy

BBVA USA,
as a Lender

By: /s/ Mark H. Wolf
Name: Mark H. Wolf
Title: Senior Vice President

CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK BRANCH,
as a Lender

By: /s/ Trudy Nelson
Name: Trudy Nelson
Title: Authorized Signatory

By: /s/ Scott W. Danvers
Name: Scott W. Danvers
Title: Authorized Signatory

CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH,
as a Lender

By: /s/ Nupur Kumar
Name: Nupur Kamar
Title: Authorized Signatory

By: /s/ Bastien Dayer
Name: Bastien Dayer
Title: Authorized Signatory

DNB CAPITAL LLC,
as a Lender

By: /s/ Leila Zomorrodian
Name: Leila Zomorrodian
Title: First Vice President

By: /s/ James Dee Grubb
Name: James Dee Grubb
Title: First Vice President

ING CAPITAL LLC,
as a Lender

By: /s/ Juli Bieser
Name: Juli Bieser
Title: Managing Director

By: /s/ Charles Hall
Name: Charles Hall
Title: Managing Director

SUMITOMO MITSUI BANKING CORPORATION,
as a Lender

By: /s/ Michael Maguire
Name: Michael Maguire
Title: Executive Director

THE TORONTO-DOMINION BANK, NEW YORK BRANCH,
as a Lender

By: /s/ Peter Kuo
Name: Peter Kuo
Title: Authorized Signatory

TRUIST BANK, formerly known as Branch Banking and Trust Company,
as a Lender

By: /s/ Greg Krablin
Name: Greg Krablin
Title: Senior Vice President

COMERICA BANK,
as a Lender

By: /s/ Mark Fuqua
Name: Mark Fuqua
Title: Executive Vice President

PNC BANK NATIONAL ASSOCIATION,
as a Lender

By: /s/ Brittany M. Lehr
Name: Brittany M. Lehr
Title: Assistant Vice President

TRUIST BANK, successor by merger to SunTrust Bank,
as a Lender

By: /s/ Brian Guffin
Name: Brian Guffin
Title: Managing Director

U.S. BANK NATIONAL ASSOCIATION,
as a Lender

By: /s/ John C. Lozano
Name: John C. Lozano
Title: Senior Vice President

ROYAL BANK OF CANADA,
as a Lender

By: /s/ Katy Berkemeyer
Name: Katy Berkemeyer
Title: Authorized Signatory

Exhibit 21.1

SUBSIDIARIES OF ANTERO RESOURCES CORPORATION

Name of Subsidiary	Jurisdiction of Organization
Monroe Pipeline LLC	Delaware
Antero Subsidiary Holdings LLC	Delaware

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Antero Resources Corporation:

We consent to the incorporation by reference in the registration statement (No. 333-191693) on Form S-8 of Antero Resources Corporation of our report dated February 12, 2020, with respect to the consolidated balance sheets of Antero Resources Corporation as of December 31, 2018 and 2019, the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes, and the effectiveness of internal control over financial reporting as of December 31, 2019, which report appears in the December 31, 2019 annual report on Form 10-K of Antero Resources Corporation. Our report, dated February 12, 2020, includes an emphasis of matter paragraph relating to the Company's adoption of Accounting Standards Codification Topic 842, *Leases.*

/s/ KPMG LLP

Denver, Colorado
February 12, 2020

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Antero Midstream Corporation:

We consent to the incorporation by reference in the registration statement (No. 333-191693) on Form S-8 of Antero Resources Corporation of our report dated February 12, 2020, with respect to the consolidated balance sheets of Antero Midstream Corporation as of December 31, 2018 and 2019, the related consolidated statements of operations and comprehensive income, partners’ capital and stockholders’ equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes, and the effectiveness of internal control over financial reporting as of December 31, 2019, which report is included in an exhibit in the December 31, 2019 annual report on Form 10-K of Antero Resources Corporation.

/s/ KPMG LLP

Denver, Colorado
February 12, 2020

Exhibit 23.3

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

February 12, 2020

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

Ladies and Gentlemen:

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (File No. 333-191693) of Antero Resources Corporation (the "Company") of information taken from our report of third party dated January 21, 2020, with respect to the Company's estimated proved reserves as of December 31, 2019.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

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

I, Paul M. Rady, Chief Executive Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2019 of Antero Resources Corporation (the "registrant");

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

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

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

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

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

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

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

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

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

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

Date: February 12, 2020

/s/ Paul M. Rady
Paul M. Rady
Chief Executive Officer

Exhibit 31.2

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

I, Glen C. Warren, Jr., President and Chief Financial Officer of Antero Resources Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2019 of Antero Resources Corporation (the “registrant”);

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

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

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

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

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

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

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

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

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

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

Date: February 12, 2020

/s/ Glen C. Warren, Jr.
Glen C. Warren, Jr.
Chief Financial Officer

Exhibit 32.1

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

In connection with this Annual Report on Form 10-K of Antero Resources Corporation for the year ended December 31, 2019, I, Paul M. Rady, Chief Executive Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2019 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2019 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: February 12, 2020

/s/ Paul M. Rady
Paul M. Rady
Chief Executive Officer

Exhibit 32.2

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

In connection with this Annual Report on Form 10-K of Antero Resources Corporation for the year ended December 31, 2019, I, Glen C. Warren, Jr., Chief Financial Officer of Antero Resources Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

1. This Annual Report on Form 10-K for the year ended December 31, 2019 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in this Annual Report on Form 10-K for the year ended December 31, 2019 fairly presents, in all material respects, the financial condition and results of operations of Antero Resources Corporation for the periods presented therein.

Date: February 12, 2020

/s/ Glen C. Warren, Jr.
Glen C. Warren, Jr.
Chief Financial Officer

Exhibit 99.1

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

January 21, 2020

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2019, of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves and present worth of certain properties in which Antero Resources Corporation (Antero) has represented it holds an interest. This evaluation was completed on January 21, 2020. The properties evaluated consist of working and royalty interests located in Ohio, Pennsylvania, and West Virginia. Antero has represented that these properties account for 99.87 percent on a million cubic feet net equivalent basis of Antero's net proved reserves as of December 31, 2019, and that the net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. We have reviewed information provided by Antero that it represents to be Antero's estimates of the net reserves, as of December 31, 2019, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Antero.

Reserves estimates included herein are expressed as net reserves as represented by Antero. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2019. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Antero after deducting all interests held by others.

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

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

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

Definition of Reserves

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Methodology and Procedures

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

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

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

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

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

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

Data provided by Antero from wells drilled through December 31, 2019, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through November 2019. Estimated cumulative production, as of December 31, 2019, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 1 month.

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

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

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

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

Primary Economic Assumptions

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

Oil, Condensate, and NGL Prices

Antero has represented that the oil, condensate, and NGL prices were based on NYMEX Light Sweet Crude Oil pricing, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil, condensate, and NGL prices were calculated using differentials furnished by Antero to the reference price of $55.65 per barrel and held constant thereafter. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $45.75 per barrel of oil and condensate and $19.14 per barrel of NGL.

Gas Prices

Antero has represented that the gas prices were based on pricing from six different indexes, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The gas prices were calculated for each property using differentials furnished by Antero to the aggregated price of $2.41 per million Btu ($/MMBtu) and held constant thereafter. Btu factors provided by Antero were used to convert prices from dollars per million Btu to dollars per thousand cubic feet of gas. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $2.57 per thousand cubic feet of gas. The indexes and prices, expressed in $/MMBtu, are shown in the following table:

Index	Average Gas Price ($/MMBtu)
NYMEX	2.63
Columbia Gas Transmission Appalachia	2.31
MICHCON	2.45
Chicago City Gates	2.56
ANR - Louisiana	2.54
CGTLA	2.51

Production and Ad Valorem Taxes

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

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Antero and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2019 values, provided by Antero, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of the wells, and reclamation and restoration associated with the abandonment, were provided by Antero for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of undeveloped reserves estimated herein.

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

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

Summary of Conclusions

Antero has represented that its estimated net proved reserves and present worth at 10 percent attributable to the evaluated properties were based on the definitions of proved reserves of the SEC. Antero's estimates of the net proved reserves and present worth attributable to these properties, which represent 99.87 percent of Antero's total proved reserves on a net equivalent basis, are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), millions of cubic feet equivalent (MMcfe), and thousands of dollars (M$):

	Estimated by Antero Net Proved Reserves and Present Worth at 10 Percent as of December 31, 2019				
Proved Reserves	**Oil and Condensate (Mbbl)**	**NGL (Mbbl)**	**Sales Gas (MMcf)**	**Gas Equivalent (MMcfe)**	**Present Worth at 10 Percent (M$)**
Marcellus and Upper Devonian					
Proved Developed					
Evaluated by DeGolyer and MacNaughton	18,599	704,686	6,393,909	10,733,619	4,152,555
Not Evaluated by DeGolyer and MacNaughton	2	759	19,846	24,412	9,927
Proved Undeveloped					
Evaluated by DeGolyer and MacNaughton	17,862	444,789	3,816,205	6,592,112	1,337,250
Not Evaluated by DeGolyer and MacNaughton	0	0	0	0	0
Total Marcellus and Upper Devonian	**36,463**	**1,150,234**	**10,229,960**	**17,350,143**	**5,499,732**
Utica					
Proved Developed					
Evaluated by DeGolyer and MacNaughton	2,816	25,073	814,616	981,948	487,976
Not Evaluated by DeGolyer and MacNaughton	3	8	159	227	186
Proved Undeveloped					
Evaluated by DeGolyer and MacNaughton	2,558	16,069	449,136	560,901	78,992
Not Evaluated by DeGolyer and MacNaughton	0	0	0	0	0
Total Utica	**5,377**	**41,150**	**1,263,911**	**1,543,076**	**567,154**

Notes:

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

In comparing the detailed net proved reserves estimates prepared by DeGolyer and MacNaughton and by Antero of the properties evaluated, differences have been found, both positive and negative, resulting in an aggregate difference of 0.6 percent for the Marcellus and Upper Devonian properties and an aggregate difference of 3.5 percent for the Utica properties when compared on the basis of net gas equivalent. It is DeGolyer and MacNaughton's opinion that there is no material difference between the net proved reserves estimates prepared by Antero and those prepared by DeGolyer and MacNaughton for those properties DeGolyer and MacNaughton evaluated. In comparing the detailed present worth at 10 percent estimates prepared by DeGolyer and MacNaughton and by Antero of the properties evaluated, differences have been found, both positive and negative, resulting in an aggregate difference of 0.1 percent for the Marcellus and Upper Devonian properties and an aggregate difference of 1.1 percent for the Utica properties when compared on the basis of present worth at 10 percent. It is DeGolyer and MacNaughton's opinion that there is no material difference between the present worth at 10 percent estimates prepared by Antero and those prepared by DeGolyer and MacNaughton for those properties we evaluated.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2019, estimated reserves.

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

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

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

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Antero dated January 21, 2020, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended the University of Texas at Austin, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1984; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and that I have in excess of 35 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Gregory K. Graves, P.E.
Gregory K. Graves, P.E.
Senior Vice President
DeGolyer and MacNaughton

Exhibit 99.4

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors or
Antero Midstream Corporation:

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

We have audited the accompanying consolidated balance sheets of Antero Midstream Corporation and subsidiaries (the Company) as of December 31, 2018 and 2019, the related consolidated statements of operations and comprehensive income, partners' capital and stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes (collectively, the consolidated financial statements). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control – Integrated 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, 2018 and 2019, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019 based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting within *Item 9A Controls and Procedures.* Our responsibility is to express an opinion on the Company's consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

Critical Audit Matters

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

Evaluation of lease classification for ongoing modifications to the gathering and compression assets

As discussed in Note 7 to the consolidated financial statements, the Company determined that the gathering and compression agreement with Antero Resources is an operating lease. The Company continues to expand its gathering and compression system to serve its customer and, as a result, the minimum volume commitments and the lease payments increase for the expanded system. The increases in volume commitments and lease payments are modifications of the arrangement that require reconsideration of the lease classification.

We identified the evaluation of lease classification for ongoing modifications to the gathering and compression assets as a critical audit matter. The evaluation of lease classification for these modified leases, including evaluating economic life as a key estimate, required significant judgment.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's process for identifying lease modifications and determining lease classification for those modifications, including controls related to the review and approval of the Company's lease modifications and the Company's review of the lease classification. We evaluated the Company's accounting memoranda and other documentation underlying the accounting conclusions reached, including application of relevant accounting guidance in regards to the modification accounting and subsequent lease classification. We evaluated the economic life used in the determination of lease classification. We evaluated fixed assets that are placed in service for new minimum volume commitments which would require reassessment of the lease.

Evaluation of the initial measurement of property and equipment and customer relationships acquired in the Antero Midstream Partners LP business combination

As discussed in Note 3 to the consolidated financial statements, on March 12, 2019, the Company acquired Antero Midstream Partners LP in a business combination. As a result of the transaction, the Company recognized property and equipment of $3,371,427 thousand and customer relationships intangible assets of $1,567,000 thousand.

We identified the evaluation of the initial measurement of property and equipment and the customer relationships acquired in the Antero Midstream Partners LP business combination as a critical audit matter. There was a high degree of subjectivity in evaluating the key assumptions used to calculate the acquisition date fair value of the property and equipment and the customer relationships intangible assets. The Company used the indirect cost and market approaches to value the property and equipment. The key assumptions included the inflationary trend and the useful lives of the underlying assets for the indirect cost method and comparable price per acre for the market approach. The Company used a discounted cash flow to value the customer relationships for which the key assumptions included forecasted revenue and the discount rate.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's business combination process, including controls related to the selection of the key assumptions used to determine the acquisition date fair value of property and equipment and customer relationships intangible assets. For the customer relationships intangible assets we evaluated the Company's forecasts of revenues based on the Company's budgets and the Antero Midstream Partners LP historical performance. In addition, we involved valuation professionals with specialized skills and knowledge who assisted in:

- Evaluating the approaches used to value the respective assets;
- Evaluating the inflationary trends, useful lives, and recent transactions based on publicly available information related to the estimated values for the property and equipment;
- Independently developing range of estimates of the fair value of the property and equipment and comparing it to the Company's estimated fair values for the property and equipment;
- Evaluating the Company's discount rate applied in the valuation of the customer relationships intangible assets by comparing the Company's inputs to publicly available data, the implied rate of return on the transaction, and the return on other acquired assets; and
- Testing the estimate of the customer relationships intangible assets fair value using the Company's cash flow assumptions and discount rate, and evaluated the result with the Company's fair value estimate.

/s/ KPMG LLP

We have served as the Company's auditor since 2016.

Denver, Colorado
February 12, 2020

Table of Contents

ANTERO MIDSTREAM CORPORATION

Consolidated Balance Sheet s

December 31, 2018 and 2019

(In thousands)

	December 31, 2018	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 2,822	1,235
Accounts receivable–Antero Resources	—	101,029
Accounts receivable–third party	—	4,574
Other current assets	87	1,720
Total current assets	2,909	108,558
Property and equipment, net	—	3,273,410
Investments in unconsolidated affiliates	43,492	709,639
Deferred tax asset	1,304	103,231
Customer relationships	—	1,498,119
Goodwill	—	575,461
Other assets, net	—	14,460
Total assets	$ 47,705	6,282,878
Liabilities and Equity		
Current liabilities:		
Accounts payable–Antero Resources	$ 731	3,146
Accounts payable–third party	28	6,645
Accrued liabilities	407	104,188
Contingent acquisition consideration	—	125,000
Taxes payable	15,678	—
Other current liabilities	—	3,105
Total current liabilities	16,844	242,084
Long-term liabilities:		
Long-term debt	—	2,892,249
Other	—	5,131
Total liabilities	16,844	3,139,464
Partners' Capital and Stockholders' Equity:		
Common shareholders—186,219 shares issued and outstanding at December 31, 2018; none issued and outstanding at December 31, 2019	(41,969)	—
IDR LLC Series B units (66 units vested at December 31, 2018; none issued and outstanding at December 31, 2019)	72,830	—
Preferred stock, $0.01 par value: none authorized or issued at December 31, 2018; 100,000 authorized at December 31, 2019		
Series A non-voting perpetual preferred stock; none designated, issued or outstanding at December 31, 2018; 12 designated and 10 issued and outstanding at December 31, 2019	—	—
Common stock, $0.01 par value; none authorized, issued or outstanding at December 31, 2018; 2,000,000 authorized and 484,042 issued and outstanding at December 31, 2019	—	4,840
Additional paid-in capital	—	3,480,139
Accumulated loss	—	(341,565)
Total partners' capital and stockholders' equity	30,861	3,143,414
Total liabilities and partners' capital and stockholders' equity	$ 47,705	6,282,878

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM CORPORATION

Consolidated Statements of Operations and Comprehensive Incom e

Years Ended December 31, 2017, 2018, and 2019

(In thousands, except per unit amounts)

	Year Ended December 31,		
	2017	2018	2019
Revenue:			
Gathering and compression–Antero Resources	$ —	—	543,538
Water handling–Antero Resources	—	—	306,010
Water handling–third party	—	—	50
Amortization of customer relationships	—	—	(57,010)
Total revenue	—	—	792,588
Operating expenses:			
Direct operating	—	—	195,818
General and administrative (including $34,933, $35,111 and $73,517 of equity-based compensation in 2017, 2018 and 2019, respectively)	41,134	43,851	118,113
Facility idling	—	—	11,401
Impairment of property and equipment	—	—	409,739
Impairment of goodwill	—	—	340,350
Impairment of customer relationships	—	—	11,871
Depreciation	—	—	95,526
Accretion and change in fair value of contingent acquisition consideration	—	—	8,076
Accretion of asset retirement obligations	—	—	187
Total operating expenses	41,134	43,851	1,191,081
Operating loss	(41,134)	(43,851)	(398,493)
Interest expense, net	—	(136)	(110,402)
Equity in earnings of unconsolidated affiliates	69,720	142,906	51,315
Income (loss) before income taxes	28,586	98,919	(457,580)
Provision for income tax benefit (expense)	(26,261)	(32,311)	102,466
Net income (loss) and comprehensive income (loss)	$ 2,325	66,608	(355,114)
Net income (loss) per share–basic and diluted	$ 0.03	0.33	(0.80)
Weighted average common shares outstanding:			
Basic	186,176	186,203	442,640
Diluted	186,176	186,203	442,640

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM CORPORATION

Consolidated Statements of Partners' Capital and Stockholders' Equity

Years Ended December 31, 2017, 2018, and 2019

(In thousands)

	Common Stock		Common Shares Representing Limited Partner	Antero Resources Midstream Management LLC Members'	Series B	Additional Paid-In	Preferred	Accumulated	Total
	Shares	Amount	Interests	Equity	Unitholders	Capital	Stock	Loss	Equity
Balance at December 31, 2016	—	$ —	—	10,269	—	—	—	—	10,269
Pre-IPO net loss and comprehensive loss	—	—	—	(4,939)	—	—	—	—	(4,939)
Pre-IPO equity-based compensation	—	—	—	10,237	—	—	—	—	10,237
Conversion of Antero Resources Midstream Management LLC to a limited partnership	—	—	15,567	(15,567)	—	—	—	—	—
Post-IPO net income and comprehensive income	—	—	6,480	—	784	—	—	—	7,264
Post-IPO equity-based compensation	—	—	24,696	—	—	—	—	—	24,696
Distributions to Antero Resources Investment LLC	—	—	(15,908)	—	—	—	—	—	(15,908)
Distributions to shareholders	—	—	(16,011)	—	—	—	—	—	(16,011)
Vesting of Series B units	—	—	(34,690)	—	34,690	—	—	—	—
Balance at December 31, 2017	—	—	(19,866)	—	35,474	—	—	—	15,608
Net income and comprehensive income	—	—	61,372	—	5,236	—	—	—	66,608
Equity-based compensation	—	—	35,111	—	—	—	—	—	35,111
Distributions to shareholders	—	—	(84,166)	—	—	—	—	—	(84,166)
Distributions to Series B unitholders	—	—	—	—	(2,300)	—	—	—	(2,300)
Vesting of Series B units	—	—	(34,420)	—	34,420	—	—	—	—
Balance at December 31, 2018	—	—	(41,969)	—	72,830	—	—	—	30,861
Distributions to unitholders	—	—	(30,543)	—	(3,720)	—	—	—	(34,263)
Net (loss) and comprehensive (loss) pre-acquisition	—	—	(13,549)	—	—	—	—	—	(13,549)
Equity-based compensation pre-acquisition	—	—	7,034	—	—	—	—	—	7,034
Exchange of common shares for shares of common stock and cash consideration paid	506,641	5,066	79,027	—	(69,110)	4,002,898	—	—	4,017,881
Issuance of Series A non-voting perpetual preferred stock	—	—	—	—	—	—	—	—	—
Dividends to stockholders	—	—	—	—	—	(461,934)	—	—	(461,934)
Equity-based compensation post-acquisition	—	—	—	—	—	66,483	—	—	66,483
Issuance of common stock upon vesting of equity-based compensation awards, net of common stock withheld for income taxes	297	3	—	—	—	(2,018)	—	—	(2,015)
Repurchases and retirement of common stock	(22,896)	(229)	—	—	—	(125,290)	—	—	(125,519)
Net loss and comprehensive loss post-acquisition	—	—	—	—	—	—	—	(341,565)	(341,565)
Balance at December 31, 2019	484,042	$ 4,840	—	—	—	3,480,139	—	(341,565)	3,143,414

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM CORPORATION

Consolidated Statements of Cash Flow s

Years Ended December 31, 2017, 2018, and 2019

(In thousands)

	Year Ended December 31, 2017	2018	2019
Cash flows provided by (used in) operating activities:			
Net income (loss)	$ 2,325	66,608	(355,114)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Distributions from Antero Midstream Partners LP, prior to the Transactions	53,491	123,186	43,492
Depreciation	—	—	95,526
Accretion and change in fair value of contingent acquisition consideration	—	—	8,263
Impairment	—	—	761,960
Deferred income tax benefit	—	(1,304)	(101,927)
Equity-based compensation	34,933	35,111	73,517
Equity in earnings of unconsolidated affiliates	(69,720)	(142,906)	(51,315)
Distributions from unconsolidated affiliates	—	—	64,320
Amortization of customer relationships	—	—	57,010
Amortization of deferred financing costs	—	148	3,183
Changes in assets and liabilities:			
Accounts receivable–Antero Resources	—	—	42,484
Accounts receivable–third party	—	—	185
Other current assets	—	(5)	(335)
Accounts payable–Antero Resources	57	674	(2,103)
Accounts payable–third party	—	28	(9,762)
Accrued liabilities	(190)	171	8,681
Income taxes payable	7,184	1,820	(15,678)
Net cash provided by operating activities	28,080	83,531	622,387
Cash flows used in investing activities:			
Additions to gathering systems and facilities	—	—	(267,383)
Additions to water handling systems	—	—	(124,607)
Investments in unconsolidated affiliates	—	—	(154,359)
Cash received on acquisition of Antero Midstream Partners LP	—	—	619,532
Cash consideration paid to Antero Midstream Partners LP unitholders	—	—	(598,709)
Change in other assets	—	—	901
Change in other liabilities	—	—	(1,050)
Net cash used in investing activities	—	—	(525,675)
Cash flows provided by (used in) financing activities:			
Distributions to Antero Resources Investment LLC	(15,691)	—	—
Distributions to unitholders and dividends to stockholders	(16,011)	(84,166)	(492,103)
Distributions to Series B unitholders	—	(2,300)	(3,720)
Distributions to preferred stockholders	—	—	(374)
Repurchases of common stock	—	—	(125,519)
Issuance of senior notes	—	—	650,000
Payments of deferred financing costs	—	(230)	(8,894)
Payments on bank credit facilities, net	—	—	(115,500)
Employee tax withholding for settlement of equity compensation awards	—	—	(2,015)
Other	—	—	(174)
Net cash used in financing activities	(31,702)	(86,696)	(98,299)
Net decrease in cash and cash equivalents	(3,622)	(3,165)	(1,587)
Cash and cash equivalents, beginning of period	9,609	5,987	2,822
Cash and cash equivalents, end of period	$ 5,987	2,822	1,235
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ —	3	83,016
Cash paid during the period for income taxes	$ 19,077	31,795	16,079
Decrease in accrued capital expenditures and accounts payable for property and equipment	$ —	—	(6,215)

See accompanying notes to consolidated financial statements.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements

Years Ended December 31, 2016, 2017, and 2018

(1) Business and Organization

Antero Midstream Corporation was originally formed as Antero Resources Midstream Management LLC in 2013 to become the general partner of Antero Midstream Partners LP ("Antero Midstream Partners"). On May 4, 2017, Antero Resources Midstream Management LLC converted from a limited liability company to a limited partnership under the laws of the State of Delaware and changed its name to Antero Midstream GP LP ("AMGP") in connection with its initial public offering. On March 12, 2019, pursuant to the Simplification Agreement, dated as of October 9, 2018, by and among AMGP, Antero Midstream Partners and certain of their affiliates (the "Simplification Agreement"), (i)AMGP was converted from a limited partnership to a corporation under the laws of the State of Delaware and changed its name to Antero Midstream Corporation (the "Conversion"), (ii) an indirect, wholly owned subsidiary of Antero Midstream Corporation was merged with and into Antero Midstream Partners, with Antero Midstream Partners surviving the merger as an indirect, wholly owned subsidiary of Antero Midstream Corporation (the "Merger"), and (iii) Antero Midstream Corporation exchanged (the "Series B Exchange" and, together with the Conversion, the Merger and the other transactions pursuant to by the Simplification Agreement, the "Transactions") each issued and outstanding Series B Unit (the "Series B Units") representing a membership interest in Antero IDR Holdings LLC ("IDR Holdings") for 176.0041 shares of its common stock, par value $0.01 per share ("AMC common stock"). As a result of the Transactions, Antero Midstream Partners is now a wholly owned subsidiary of Antero Midstream Corporation and former shareholders of AMGP, unitholders of Antero Midstream Partners, including Antero Resources Corporation ("Antero Resources"), and holders of Series B Units now own AMC common stock. Unless the context otherwise requires, references to the "Company," "we," "us" or "our" refer to (i) for the period prior to March 13, 2019, AMGP and its consolidated subsidiaries, which did not include Antero Midstream Partners and its subsidiaries, and (ii) for the period beginning on March 13, 2019, Antero Midstream Corporation and its consolidated subsidiaries, including Antero Midstream Partners and its subsidiaries Antero Midstream LLC, Antero Water LLC ("Antero Water"), Antero Treatment LLC and Antero Midstream Finance Corporation ("Finance Corp").

We are a growth-oriented midstream company formed to own, operate and develop midstream energy infrastructure primarily to service Antero Resources and its production and completion activity in the Appalachian Basin's Marcellus Shale and Utica Shale located in West Virginia and Ohio. Our assets consist of gathering pipelines, compressor stations, interests in processing and fractionation plants, and water handling assets. The Company, through Antero Midstream Partners and its affiliates, provides midstream services to Antero Resources under long-term contracts.

The Company's gathering and compression assets comprise of high and low pressure gathering pipelines, compressor stations, and processing and fractionation plants that collect and process natural gas and NGLs from Antero Resources' wells in West Virginia and Ohio. The Company's water handling assets include two independent systems that deliver fresh water from sources including the Ohio River, local reservoirs and several regional waterways.

The Company, through Antero Midstream Partners, also has a 15% equity interest in the gathering system of Stonewall Gas Gathering LLC ("Stonewall") and a 50% equity interest in a joint venture to develop processing and fractionation assets with MarkWest Energy Partners, L.P. ("MarkWest"), a wholly owned subsidiary of MPLX, LP ("MPLX") (the "Joint Venture"). See Note 16—Investments in Unconsolidated Affiliates.

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 have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). In the opinion of management, these consolidated statements include all adjustments (consisting of normal and recurring accruals) considered necessary for a fair presentation of the Company's financial position as of December 31, 2018 and 2019, and the results of the Company's operations and its cash flows for the years ended December 31, 2017, 2018 and 2019. The Company has no items of other comprehensive income (loss); therefore, net income (loss) is equal to comprehensive income (loss).

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

Certain costs of doing business incurred and charged to the Company by Antero Resources have been reflected in the accompanying consolidated financial statements. These costs include general and administrative expenses provided to the Company by Antero Resources in exchange for:

- business services, such as payroll, accounts payable and facilities management;
- corporate services, such as finance and accounting, legal, human resources, investor relations and public and regulatory policy; and
- employee compensation, including equity-based compensation.

Transactions between the Company and Antero Resources have been identified in the consolidated financial statements (see Note 6—Transactions with Affiliates).

(b) Principles of Consolidation

The accompanying consolidated financial statements include (i) for the period prior to March 13, 2019, the accounts of AMGP and its consolidated subsidiaries, which did not include Antero Midstream Partners and its subsidiaries, and (ii) for the period beginning on March 13, 2019, the accounts of Antero Midstream Corporation and its consolidated subsidiaries, including Antero Midstream Partners and its subsidiaries, which were acquired in the Transactions. See Note 3—Business Combination. All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements.

Prior to the Transactions on March 12, 2019, AMGP had determined that Antero Midstream Partners was a variable interest entity ("VIE") for which AMGP was not the primary beneficiary and therefore did not consolidate. AMGP concluded that Antero Resources was the primary beneficiary of Antero Midstream Partners and Antero Resources consolidated its financial results. Antero Resources was the primary beneficiary based on its power to direct the activities that most significantly impacted Antero Midstream Partners' economic performance and its obligations to absorb losses or receive benefits of Antero Midstream Partners that would be significant to Antero Midstream Partners. Antero Resources owned approximately 53% of the outstanding limited partner interests in Antero Midstream Partners prior to the Transactions and its officers and management group also acted as management of Antero Midstream Partners. AMGP did not own any limited partnership interests in Antero Midstream Partners and had no capital interests in Antero Midstream Partners. AMGP did not provide financial support to Antero Midstream Partners.

AMGP's ownership of the non-economic general partner interest in Antero Midstream Partners prior to the Transactions provided AMGP with significant influence over Antero Midstream Partners, but not control over the decisions that most significantly impacted the economic performance of Antero Midstream Partners. AMGP's indirect ownership of the IDRs of Antero Midstream Partners prior to the Transactions entitled AMGP to receive cash distributions from Antero Midstream Partners when distributions exceeded certain target amounts. AMGP's ownership of these interests prior to the Transactions did not require AMGP to provide financial support to Antero Midstream Partners. AMGP obtained these interests upon its formation for no consideration. Therefore, AMGP had no cost basis and classified its investment in Antero Midstream Partners as a long term investment. Prior to the Transactions, AMGP's share of Antero Midstream Partner's earnings were a result of AMGP's ownership of the IDRs was accounted for using the equity method of accounting. AMGP recognized distributions earned from Antero Midstream Partners as "Equity in earnings of unconsolidated affiliates" on its statement of operations in the period in which they were earned and were allocated to AMGP's capital account. AMGP's long-term interest in the IDRs on the balance sheet was recorded in "Investment in unconsolidated affiliates." The ownership of the general partner interests and IDRs did not provide AMGP with any claim to the assets of Antero Midstream Partners other than the balance in its Antero Midstream Partners capital account. Income related to the IDRs was recognized as earned and increased AMGP's capital account and equity investment. When these distributions were paid to AMGP, they reduced its capital account and its equity investment in Antero Midstream Partners.

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

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

(c) Revenue Recognition

The Company, through Antero Midstream Partners and its affiliates, provides gathering and compression and water handling services under fee-based contracts primarily based on throughput or at cost plus a margin. Certain of these contracts contain operating leases of the Company's assets under GAAP. Under these arrangements, the Company receives fees for gathering gas products, compression services, and water handling services. The revenue the Company earns from these arrangements is directly related to (1) in the case of natural gas gathering and compression, the volumes of metered natural gas that it gathers, compresses, and delivers to natural gas compression sites or other transmission delivery points, (2) in the case of fresh water services, the quantities of fresh water delivered to its customers for use in their well completion operations, (3) in the case of wastewater treatment services performed by the Company prior to idling of the Clearwater Facility (as defined below) in September 2019, the quantities of wastewater treated for our customers, (4) in the case of wastewater services provided by third parties, the third-party costs the Company incurs plus 3%, or (5) in the case of flowback and produced water performed by the Company, a cost of service fee based on the costs incurred by the Company. The Company recognizes revenue when it satisfies a performance obligation by delivering a service to a customer or the use of leased assets to a customer. See Note 7—Revenue for the Company's required disclosures under Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers.* The Company includes lease revenue within revenues by service.

(d) Use of Estimates

The preparation of the consolidated financial statements and notes in conformity with GAAP requires that management formulate estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingent liabilities. Items subject to estimates and assumptions include the useful lives of property and equipment, the valuation of assets and liabilities acquired from Antero Midstream Partners, as well as the valuation of accrued liabilities, among others. Although management believes these estimates are reasonable, actual results could differ from these estimates.

(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.

(f) Property and Equipment

Property and equipment primarily consists of gathering pipelines, compressor stations and the wastewater treatment facility and related landfill (collectively, the "Clearwater Facility") used for the disposal of salt therefrom and fresh water delivery pipelines and facilities stated at historical cost less accumulated depreciation, amortization and impairment. The Company capitalizes construction-related direct labor and material costs. Maintenance and repair costs are expensed as incurred.

Depreciation of property and equipment is computed using the straight-line method over the estimated useful lives and salvage values of assets. The depreciation of fixed assets recorded under operating lease agreements is included in depreciation expense. Uncertainties that may impact these estimates of useful lives include, among others, changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions, and supply and demand for the Company's services in the areas in which it operates. When assets are placed into service, management makes estimates with respect to useful lives and salvage values that management believes are reasonable.

Amortization of landfill airspace consists of the amortization of landfill capital costs, including those that have been incurred and capitalized and estimated future costs for landfill development and construction, as well as the amortization of asset retirement costs arising from landfill final capping, closure, and post-closure obligations. Amortization expense is recorded on a units-of-consumption basis, applying cost as a rate per-cubic yard. The rate per-cubic yard is calculated by dividing each component of the amortizable basis of the landfill by the number of cubic yards needed to fill the corresponding asset's airspace. Landfill capital costs and closure and post-closure asset retirement costs are generally incurred to support the operation of the landfill over its entire operating life and are, therefore, amortized on a per-cubic yard basis using a landfill's total airspace capacity. Estimates of disposal capacity and future development costs are created using input from independent engineers and internal technical teams and are reviewed at least annually.

The Company evaluates its long-lived assets 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. The Company recognized an impairment with respect to the Clearwater Facility during the year ended December 31, 2019. See Note 4—Clearwater Facility Impairment.

(g) Asset Retirement Obligations

The Company's asset retirement obligations include its obligation to close, maintain, and monitor landfill cells and support facilities. After the entire landfill reaches capacity and is certified closed, the Company must continue to maintain and monitor the landfill for a post-closure period, which generally extends for 30 years. The Company records the fair value of its landfill retirement obligations as a liability in the period in which the regulatory obligation to retire a specific asset is triggered. For the Company's individual landfill cells, the required closure and post-closure obligations under the terms of its permits and its intended operation of the landfill cell are triggered and recorded when the cell is placed into service and salt is initially disposed in the landfill cell. The fair value is based on the total estimated costs to close the landfill cell and perform post-closure activities once the landfill cell has reached capacity and is no longer accepting salt. Retirement obligations are increased each year to reflect the passage of time by accreting the balance at the weighted average credit-adjusted risk-free rate that is used to calculate the recorded liability, with accretion charged to direct costs. Actual cash expenditures to perform closure and post-closure activities reduce the retirement obligation liabilities as incurred. After initial measurement, asset retirement obligations are adjusted at the end of each period to reflect changes, if any, in the estimated future cash flows underlying the obligation. Landfill retirement assets are capitalized as the related retirement obligations are incurred, and are amortized on a units-of-consumption basis as the disposal capacity is consumed.

Asset retirement obligations are recorded for fresh water impoundments and waste water pits when an abandonment date is identified. The Company records the fair value of its freshwater impoundment and waste water pit retirement obligations as liabilities in the period in which the regulatory obligation to retire a specific asset is triggered. The fair value is based on the total reclamation costs of the assets. Retirement obligations are increased each year to reflect the passage of time by accreting the balance at the weighted average credit-adjusted risk-free rate that is used to calculate the recorded liability, with accretion charged to direct costs. Actual cash expenditures to perform remediation activities reduce the retirement obligation liabilities as incurred. After initial measurement, asset retirement obligations are adjusted at the end of each period to reflect changes, if any, in the estimated future cash flows underlying the obligation. Fresh water impoundments and wastewater pit retirement assets are capitalized as the related retirement obligations are incurred, and are amortized on a straight-line basis until reclamation.

The Company 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, flowback and produced water facilities and the wastewater treatment facility upon abandonment. See Note 4—Clearwater Facility Impairment.

(h) Litigation and Other Contingencies

A liability is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. The Company regularly reviews contingencies to determine the adequacy of our accruals and related disclosures. The ultimate amount of losses, if any, may differ from these estimates.

The Company accrues losses associated with environmental obligations when such losses are probable and can be reasonably estimated. Accruals for estimated environmental losses are recognized no later than at the time a remediation feasibility study, or an evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or as circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable.

As of December 31, 2018 and 2019, the Company had not recorded any liabilities for litigation, environmental, or other contingencies.

(i) Equity-Based Compensation

The Company's consolidated financial statements include equity-based compensation costs related to awards granted by its own plans, as in place before and after the Transactions, as well as costs allocated by Antero Resources for grants made prior to the Transactions. Costs allocated from Antero Resources are offset to additional paid in capital on the consolidated balance sheet. See Note 6—Transactions with Affiliates for additional information regarding Antero Resources' allocation of expenses to the Company. For awards granted under its own plan, the Company recognizes compensation cost related to all equity-based awards in the financial statements based on the estimated grant date fair value. The Company is authorized to grant various types of equity-based compensation awards, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent awards and other types of awards. The grant date fair values are determined based on the type of award and may utilize market prices on the date of grant, Black-Scholes option-pricing model, Monte Carlo simulations or other acceptable valuation methodologies, as appropriate for the type of equity-based award. Compensation cost is recognized ratably over the applicable vesting or service period. Forfeitures are accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. See Note 12—Equity-Based Compensation.

(j) 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. The Company regularly reviews its tax positions in each significant taxing jurisdiction during the process of evaluating its tax provision. The Company makes adjustments to its tax provision when: (i) facts and circumstances regarding a tax position change, causing a change in management's judgment regarding that tax position; and/or (ii) a tax position is effectively settled with a tax authority at a differing amount.

(k) Fair Value Measures

The Financial Accounting Standards Board (the "FASB") ASC Topic 820, *Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., the initial recognition of asset retirement obligations and impairments of long-lived assets). The 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, that are observable for the asset or liability, either directly or indirectly.

The carrying values on the consolidated balance sheet of the Company's cash and cash equivalents, accounts receivable—Antero Resources, accounts receivable—third party, other current assets, accounts payable—Antero Resources, accounts payable—third party, accrued liabilities, other current liabilities, other liabilities and the Credit Facility (as defined in Note 10—Long-Term Debt) approximate fair values due to their short-term maturities. The assets and liabilities of Antero Midstream Partners were recorded at fair value as of the acquisition date, March 12, 2019 (see Note 3—Business Combination). Additionally, the Company uses certain fair valuation techniques in performing its annual goodwill impairment test described below.

(l) Investments in Unconsolidated Affiliates

The Company uses the equity method to account for its investments in companies if the investment provides the Company with the ability to exercise significant influence over, but not control of, the operating and financial policies of the investee. The Company's consolidated net income includes the Company's proportionate share of the net income or loss of such companies. The Company's judgment regarding the level of influence over each equity method investee includes considering key factors such as the Company's ownership interest, representation on the board of directors and participation in policy-making decisions of the investee and material intercompany transactions. See Note 16—Investments in Unconsolidated Affiliates.

(m) Business Combinations

The Company recognizes and measures the assets acquired and liabilities assumed in a business combination based on their estimated fair values at the acquisition date, with any remaining difference recorded as goodwill. For acquisitions, management engages an independent valuation specialist, as applicable, to assist with the determination of fair value of the assets acquired, liabilities assumed, and goodwill, based on recognized business valuation methodologies. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition, and not later than one year from the acquisition date, the Company will record any material adjustments to the initial estimate based on new information obtained that would have existed as of the acquisition date. An adjustment that arises from information obtained that did not exist as of the date of the acquisition will be recorded in the period of the adjustment. Acquisition-related costs are expensed as incurred in connection with each business combination. See Note 3—Business Combination.

(n) Goodwill and Intangible Assets

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized, but rather is tested for impairment annually in the fourth quarter and when events or changes in circumstances indicate that the fair value of a reporting unit with goodwill has been reduced below its carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. The fair value of each reporting unit is determined and compared to the carrying value of the reporting unit. The fair value is calculated using the expected present value of future cash flows method. Significant assumptions used in the cash flow forecasts include future net operating margins, future volumes, discount rates and future capital requirements. If the fair value of the reporting unit is less than the carrying value, including goodwill, the excess of the book value over the fair value of goodwill is charged to net income as an impairment expense.

Amortization of intangible assets with definite lives is calculated using the straight-line method, which is reflective of the benefit pattern in which the estimated economic benefit is expected to be received over the estimated useful life of the intangible asset. Intangible assets subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the intangible asset may not be recoverable. If the sum of the expected undiscounted future cash flows related to the asset is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. See Note 4—Clearwater Facility Impairment and Note 5—Goodwill and Intangibles.

(o) Treasury Share Retirement

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

(p) Recently Issued Accounting Standards

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

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

(3) Business Combination

On March 12, 2019, AMGP and Antero Midstream Partners completed the Transactions. The Transactions have been accounted for using the acquisition method of accounting with Antero Midstream Corporation identified as the acquirer of Antero Midstream Partners.

The components of the fair value of consideration transferred are as follows (in thousands):

Fair value of shares of AMC common stock issued(1)	$	4,017,881
Cash		598,709
Total fair value of consideration transferred	$	4,616,590

(1) The fair value of each share of AMC common stock issued in connection with the Transactions was determined to be $12.54, the closing price of AMGP common shares on March 12, 2019.

The final purchase price allocation of the Transactions, and final adjustments thereto, are summarized in the table below. The fair value of assets acquired and liabilities assumed at March 12, 2019 were as follows (in thousands):

		As Originally Reported		Adjustments		As Adjusted
Cash and cash equivalents	$	619,532		—		619,532
Accounts receivable–Antero Resources		142,312		—		142,312
Accounts receivable–third party		117		—		117
Other current assets		1,150		—		1,150
Property and equipment, net		3,639,148		(267,721)		3,371,427
Investments in unconsolidated affiliates		1,090,109		(521,824)		568,285
Customer relationships		558,000		1,009,000		1,567,000
Other assets, net		42,887		—		42,887
Total assets acquired		6,093,255		219,455		6,312,710
Accounts payable–Antero Resources		3,316		—		3,316
Accounts payable–third party		30,674		—		30,674
Accrued liabilities		87,021		—		87,021
Other current liabilities		537		—		537
Long-term debt		2,364,935		—		2,364,935
Contingent acquisition consideration		116,924		—		116,924
Other liabilities		8,524		—		8,524
Total liabilities assumed		2,611,931		—		2,611,931
Net assets acquired, excluding goodwill		3,481,324		219,455		3,700,779
Goodwill		1,135,266		(219,455)		915,811
Net assets acquired	$	4,616,590	$	—	$	4,616,590

Adjustments to the preliminary purchase price allocation stem mainly from additional information obtained by the Company in between the closing of the Transactions on March 12, 2019 and December 31, 2019 about facts and circumstances that existed as of the date of the Transactions, including updates to the completion of certain valuations to determine the underlying fair value of certain assets. The decrease in the fair value of the property and equipment resulted in a $10 million reversal of Depreciation in the consolidated statement of operations. The increase in the fair value of customer relationships resulted in a $21 million increase in Amortization of customer relationships in the consolidated statement of operations. All customer relationships are subject to amortization, which will be recognized over a weighted-average period of 23 years.

The purchase price allocation resulted in the recognition of $575 million of goodwill in three reporting units within the Company's gathering and processing segment and $340 million of goodwill in two reporting units within its water handling segment.

Substantially all of goodwill is expected to be deductible for tax purposes. Goodwill represents the efficiencies realized with simplifying our corporate structure to own, operate and develop midstream energy infrastructure primarily to service Antero Resources.

The Company's financial statements include $6 million of acquisition-related costs associated with the Transactions. These costs were expensed as general and administrative costs.

(4) Clearwater Facility Impairment

On September 18, 2019, the Company commenced a strategic evaluation of the Clearwater Facility at which time, such facility was idled. Based on the preliminary results of the evaluation and ongoing discussions with the facility's contractor, the Company determined that the facility is expected to be idled for the foreseeable future. Accordingly, the Company performed an interim impairment analysis of the facility and determined: (i) to reduce the carrying value of the facility to its estimated salvage value, which included the land associated with the Clearwater Facility; (ii) the fair value of the goodwill assigned to the wastewater treatment reporting unit was less than its carrying value resulting in an impairment charge to goodwill; and (iii) the customer relationships intangible asset was impaired. The following table shows the impairment charges for the year ended December 31, 2019 related to the Clearwater Facility as updated to reflect the final purchase price allocation of the Transactions (in thousands):

Impairment of property and equipment	$	408,882
Impairment of goodwill		42,290
Impairment of customer relationships		11,871
Total impairment expense	$	463,043

The Company incurred $11 million in facility idling costs for the care and maintenance of the Clearwater Facility during the period from September 18, 2019 through December 31, 2019.

(5) Goodwill and Intangibles

The Company evaluates goodwill for impairment annually during the fourth quarter and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit with goodwill is less than its carrying amount. Significant assumptions used to estimate the reporting units' fair value include the discount rate as well as estimates of future cash flows, which are impacted primarily by commodity prices and producer customers' development plans (which impact volumes and capital requirements).

During the third quarter of 2019, the Company performed an interim impairment analysis of the goodwill related to the wastewater treatment reporting unit recorded in connection with the Transactions due to the Company's strategic evaluation of the Clearwater Facility. As a result of this evaluation, the Company incurred impairment charges to the goodwill and customer relationships intangible asset associated with the Clearwater Facility, which is in the water handling segment. See Note 4—Clearwater Facility Impairment.

The Company performed its annual goodwill impairment test in the fourth quarter of 2019. As a result of this test, the Company incurred impairment charges of $298 million to its fresh water delivery and services reporting unit, which is in the water handling segment. This was primarily due to decreased water volumes driven by decreased drilling and increased use of water blending operations by Antero Resources.

The changes in the carrying amount in goodwill for the year ended December 31, 2019 were as follows (in thousands):

	Gathering and Processing	Water Handling	Consolidated Total
Goodwill as of December 31, 2018	$ —	—	—
Goodwill acquired[1]	575,461	340,350	915,811
Impairment of goodwill	—	(340,350)	(340,350)
Goodwill as of December 31, 2019	$ 575,461	—	575,461

(1) See Note 3—Business Combination.

All customer relationships are subject to amortization and will be amortized over a weighted-average period of 23 years. The changes in the carrying amount of customer relationships for the year ended December 31, 2019 were as follows (in thousands):

Customer relationships as of December 31, 2018	$ —
Customer relationships acquired[1]	1,567,000
Accumulated amortization	(57,010)
Impairment	(11,871)
Customer relationships as of December 31, 2019	$ 1,498,119

(1) See Note 3—Business Combination.

Future amortization expense is as follows (in thousands):

Year ending December 31, 2020	$ 70,672
Year ending December 31, 2021	70,672
Year ending December 31, 2022	70,672
Year ending December 31, 2023	70,672
Year ending December 31, 2024	70,672
Thereafter	1,144,759
Total	$ 1,498,119

(6) Transactions with Affiliates

(a) Revenues

Substantially all revenues earned in the year ended December 31, 2019 were earned from Antero Resources, under various agreements for gathering and compression and water handling services. Revenues earned from gathering and processing services consists of lease income. There were no such revenues earned by AMGP for the years ended December 31, 2017 and 2018.

(b) Accounts receivable–Antero Resources, and Accounts payable–Antero Resources

Accounts receivable—Antero Resources represents amounts due from Antero Resources, primarily related to gathering and compression services and water handling services. Accounts payable—Antero Resources represents amounts due to Antero Resources for general and administrative and other costs.

(c) Allocation of Costs Charged by Antero Resources

The employees supporting the Company's operations are concurrently employed by Antero Resources and Antero Midstream Corporation. Direct operating expense includes costs charged to the Company of $6 million during the year ended December 31, 2019, related to services provided by employees associated with the operation of the Company's gathering lines, compressor stations, and water handling assets. There were no such charges to AMGP during the years ended December 31, 2017 and 2018. For the years ended December 31, 2017, 2018 and 2019, general and administrative expenses charged to the Company by Antero Resources were

$0.7 million, $0.5 million, and $33 million, respectively. These costs relate to: (i) various business services, including payroll processing, accounts payable processing and facilities management, (ii) various corporate services, including legal, accounting, treasury, information technology and human resources and (iii) compensation, including certain equity-based compensation. These expenses are charged to the Company based on the nature of the expenses and are apportioned based on a combination of the Company's proportionate share of gross property and equipment, capital expenditures and labor costs, as applicable. The Company reimburses Antero Resources directly for all general and administrative costs charged to it, with the exception of noncash equity compensation attributed to the Company for awards issued prior to the Transactions under Antero Resources' long-term incentive plan and the Antero Midstream Corporation Long Term Incentive Plan (the "AMC LTIP"). See Note 12—Equity-Based Compensation.

(7) Revenue

(a) Revenue from Contracts with Customers

All of the Company's revenues are derived from service contracts with customers and are recognized when the Company satisfies a performance obligation by delivering a service to a customer. The Company derives substantially all of its revenues from Antero Resources. The following sets forth the nature, timing of satisfaction of performance obligations, and significant payment terms of the Company's contracts with Antero Resources.

Gathering and Compression Agreement

Pursuant to the gathering and compression agreement with Antero Resources, Antero Resources has dedicated substantially all of its current and future acreage in West Virginia, Ohio and Pennsylvania to the Company for gathering and compression services except for acreage subject to third-party commitments or pre-existing dedications. The Company also has an option to gather and compress natural gas produced by Antero Resources on any additional acreage it acquires during the term of the agreement outside of West Virginia, Ohio and Pennsylvania on the same terms and conditions. In December 2019, the Company and Antero Resources agreed to extend the initial term of the gathering and compression agreement to 2038 and established a growth incentive fee program whereby low pressure gathering fees will be reduced from 2020 through 2023 to the extent Antero Resources achieves certain volumetric targets. Upon completion of this term, the gathering and compression agreement will continue in effect from year to year until such time as the agreement is terminated, effective upon an anniversary of the effective date of the agreement, by either the Company or Antero Resources on or before the 180th day prior to the anniversary of such effective date.

Under the gathering and compression agreement, the Company receives a low pressure gathering fee, a high pressure gathering fee and a compression fee, in each case subject to CPI-based adjustments. In addition, the agreement stipulates that the Company receives a reimbursement for the actual cost of electricity used at its compressor stations.

The Company determined that the gathering and compression agreement is an operating lease as Antero Resources obtains substantially all of the economic benefit of the asset and has the right to direct the use of the asset. The gathering system is an identifiable asset within the gathering and compression agreement, and it consists of underground low pressure pipelines that generally connect and deliver gas from specific well pads to compressor stations to compress the gas before delivery to underground high pressure pipelines that transport the gas to a third-party pipeline or plant. The gathering system is considered a single lease due to the interrelated network of the assets. The Company accounts for its lease and non-lease components as a single lease component as the lease component is the predominant component. The non-lease components consist of operating, oversight and maintenance of the gathering system, which are performed on time-elapsed measures. All lease payments under the future Minimum Volume Commitments discussed below are considered to be in-substance fixed lease payments under the gathering and compression agreement.

The Company recognizes revenue when low pressure volumes are delivered to a compressor station, compression volumes are delivered to a high pressure line and high pressure volumes are delivered to a processing plant or transmission pipeline. The Company invoices the customer the month after each service is performed, and payment is due in the same month.

Water Services Agreement

The Company is party to a water services agreement with Antero Resources, which commenced on September 23, 2015, whereby the Company agreed to provide certain water handling services to Antero Resources within an area of dedication in defined service areas in West Virginia, Ohio and other locations. Upon completion of the initial term 20-year term, the water services agreement will continue in effect from year to year until such time as the agreement is terminated, effective upon an anniversary of the effective date of the agreement, by either the Company or Antero Resources on or before the 180th day prior to the anniversary of such effective date. Under the agreement, the Company receives a fixed fee per barrel in West Virginia, Ohio and all other locations for fresh water deliveries by pipeline directly to the well site. Additionally, the Company receives a fixed fee per barrel for fresh water delivered by truck to high-rate transfer facilities. For flowback and produced water blending services, the Company receives a cost of service fee based on the costs incurred by the Company. Antero Resources also agreed to pay the Company a fixed fee per barrel for wastewater treatment at the Clearwater Facility, which was idled in the third quarter of 2019 and we expect will remain idled for the foreseeable future. All such fees under the agreement are subject to annual CPI-based adjustments and additional fees based on certain costs. As of the start of 2020, there are no minimum volume commitments under the water services agreement.

Under the water services agreement, the Company may also contract with third parties to provide water services to Antero Resources. Antero Resources reimburses the Company for third-party out-of-pocket costs plus a 3% markup. On February 12, 2019, Antero Resources and Antero Midstream Partners amended and restated the water services agreement to, among other things, make certain clarifying changes with respect to the CPI adjustments. The initial term of the water services agreement runs to 2035. The Company satisfies its performance obligations and recognizes revenue when the fresh water volumes have been delivered to the hydration unit of a specified well pad, flowback and produced water blending services have been completed and the wastewater volumes have been delivered to the Clearwater Facility. The Company invoices the customer the month after water services are performed, and payment is due in the same month. For services contracted through third-party providers, the Company's performance obligation is satisfied when the service to be performed by the third-party provider has been completed. The Company invoices the customer after the third-party provider billing is received, and payment is due in the same month.

Minimum Volume Commitments

The gathering and compression agreement includes certain minimum volume commitment provisions. If and to the extent Antero Resources requests that the Company construct new high pressure lines and compressor stations, the gathering and compression agreement contains minimum volume commitments that require Antero Resources to utilize or pay for 75% and 70%, respectively, of the capacity of such new construction for 10 years. The Company recognizes lease income from its minimum volume commitments under its gathering and compression agreement on a straight-line basis and additional operating lease income is earned when excess volumes are delivered under the contract. The Company is not party to any leases that have not commenced. Minimum volume commitments for fresh water deliveries under the water services agreement concluded at December 31, 2019.

Minimum revenue amounts under the gathering and compression minimum volume commitments are as follows (in thousands):

2020	$	204,988
2021		209,556
2022		209,556
2023		209,556
2024		210,130
Thereafter		584,167
Total	$	1,627,953

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

(b) Disaggregation of Revenue

In the following table, revenue is disaggregated by type of service and type of fee. The table also identifies the reportable segment to which the disaggregated revenues relate. AMGP did not earn revenue for the years ended December 31, 2017 and 2018. For more information on reportable segments, see Note 17—Reporting Segments.

(in thousands)	Year Ended December 31, 2019	Segment to which revenues relate
Revenue from contracts with customers		
Type of service		
Gathering—low pressure	$ 254,350	Gathering and Processing(1)
Gathering—high pressure	151,283	Gathering and Processing(1)
Compression	137,905	Gathering and Processing(1)
Fresh water delivery	157,633	Water Handling
Wastewater treatment	25,058	Water Handling
Other fluid handling	123,369	Water Handling
Amortization of customer relationships(2)	(29,850)	Gathering and Processing
Amortization of customer relationships(2)	(27,160)	Water Handling
Total	$ 792,588	
Type of contract		
Per Unit Fixed Fee	$ 543,538	Gathering and Processing(1)
Per Unit Fixed Fee	182,691	Water Handling
Cost plus 3%	123,030	Water Handling
Cost of service fee	339	Water Handling
Amortization of customer relationships(2)	(29,850)	Gathering and Processing
Amortization of customer relationships(2)	(27,160)	Water Handling
Total	$ 792,588	

(1) Revenue related to the gathering and processing segment is classified as lease income related to the gathering system.

(2) Fair value of customer contracts acquired as part of the Transactions discussed in Note 3—Business Combination.

(c) Transaction Price Allocated to Remaining Performance Obligations

The majority of the Company's service contracts have a term greater than one year. As such, the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's service 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.

The remainder of our service contracts, which relate to contracts with third parties, are short-term in nature with a contract term of one year or less. Accordingly, the Company is exempt from 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.

(d) Contract Balances

Under the Company's service contracts, the Company invoices customers after its performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's service contracts do not give rise to contract assets or liabilities. At December 31, 2019, the Company's receivables with customers were $101 million. There were no receivables from customers as of December 31, 2018.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

(8) Property and Equipment

The Company's investment in property and equipment for the period presented is summarized in the following table. AMGP had no property and equipment at December 31, 2018.

(in thousands)	Estimated useful lives	December 31, 2019
Land	n/a	$ 23,549
Gathering systems and facilities	40-50 years[1]	2,375,241
Fresh water permanent buried pipelines and equipment	10-20 years	602,230
Fresh water surface pipelines and equipment	1-5 years	48,594
Landfill	n/a[2]	1,244
Heavy trucks and equipment	3-5 years	6,617
Above ground storage tanks	5-10 years	3,418
Construction-in-progress	n/a	300,165
Total property and equipment		3,361,058
Less accumulated depreciation		(87,648)
Property and equipment, net		$ 3,273,410

(1) Gathering systems and facilities are recognized as a single-leased asset with no residual value.

(2) Amortization of landfill costs is recorded over the life of the landfill on a units-of-consumption basis.

(9) Income Taxes

For the years ended December 31, 2017, 2018, and 2019, income tax expense consisted of the following:

	Year Ended December 31,		
(in thousands)	2017	2018	2019
Current income tax expense (benefit)	$ 26,261	33,615	(539)
Deferred income tax expense (benefit)	—	(1,304)	(101,927)
Total income tax expense (benefit)	$ 26,261	32,311	(102,466)

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

	Year Ended December 31,		
(in thousands)	2017	2018	2019
Federal income tax expense (benefit)	$ 10,005	20,773	(96,092)
State income tax expense (benefit), net of federal benefit	952	4,133	(17,089)
Non-deductible equity-based compensation	13,296	8,087	13,694
Non-deductible IPO expenses	1,948	1	—
Charitable contributions	—	—	(2,473)
Other	60	(683)	(506)
Total income tax expense (benefit)	$ 26,261	32,311	(102,466)

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

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 as follows:

	Year Ended December 31,	
(in thousands)	**2018**	**2019**
Deferred tax assets:		
Net operating loss carryforwards	$ —	68,614
Investment in Antero Midstream Partners	—	28,381
Transaction costs	1,304	2,465
Equity-based compensation	—	1,298
Charitable contributions	—	2,473
Total deferred tax assets	1,304	103,231
Valuation allowance	—	—
Net deferred tax assets	1,304	103,231
Deferred tax liabilities:		
Net deferred tax liabilities	—	—
Net deferred tax assets (liabilities)	$ 1,304	103,231

As of December 31, 2019, the Company has a deferred tax asset in its Investment in Antero Midstream Partners of $28 million. At the time of the Transactions on March 12, 2019, the investment in Antero Midstream Partners was recorded at fair value for both GAAP and income tax purposes. The GAAP versus tax treatment of activity occurring after the transaction, such as the treatment of impairments and differing recovery rates of the underlying assets, gave rise to the deferred tax asset. Due to Antero Midstream Partners' strong history of pre-tax earnings, the Company believes the benefits of this deferred tax asset will be realized. Additionally, as of December 31, 2019, the Company has U.S. federal and state NOL carryforwards before the effect of income taxes of $277 million and $202 million, respectively, which have no expiration date.

In assessing the realizability of all of the 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 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 realize the benefits of these deductible differences and thus has not recorded a valuation allowance.

(10) Long-term Debt

On May 9, 2018, AMGP entered into a credit facility (the "AMGP Credit Facility") with a bank, which provided for a line of credit of up to $12 million. At December 31, 2018, AMGP had no borrowings under the AMGP Credit Facility. In connection with the Transactions, the AMGP Credit Facility was terminated on March 12, 2019.

AMGP had no long-term debt at December 31, 2018. Antero Midstream Corporation's long-term debt was as follows at December 31, 2019:

(in thousands)	**December 31, 2019**
Credit Facility (a)	$ 959,500
5.375% senior notes due 2024 (b)	652,600
5.75% senior notes due 2027 (c)	653,250
5.75% senior notes due 2028 (d)	650,000
Net unamortized debt issuance costs	(23,101)
Total long-term debt	$ 2,892,249

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

(a) Antero Midstream Partners Revolving Credit Facility

Antero Midstream Partners, an indirect, wholly owned subsidiary of Antero Midstream Corporation, as borrower (the "Borrower"), has a senior secured revolving credit facility (the "Credit Facility") with a consortium of banks. Lender commitments under the Credit Facility currently are $2.13 billion. At December 31, 2019, the Borrower had borrowings under the Credit Facility of $960 million with a weighted average interest rate of 3.15%. No letters of credit were outstanding at December 31, 2019 under the Credit Facility. The maturity date of the facility is October 26, 2022. The Credit Facility includes fall away covenants and lower interest rates that are triggered if and when the Borrower is assigned an Investment Grade Rating (as defined below).

Under the Credit Facility, "Investment Grade Period" is a period that, as long as no event of default has occurred and the Borrower is in pro forma compliance with the financial covenants under the Credit Facility, commences when the Borrower elects to give notice to the Administrative Agent that the Borrower 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 & Poor's (an "Investment Grade Rating")). An Investment Grade Period can end at the Borrower's election.

During a period that is not an Investment Grade Period, the Credit Facility is ratably secured by mortgages on substantially all of the Borrower's properties, including the properties of its subsidiaries, and guarantees from its subsidiaries. During an Investment Grade Period, the liens securing the obligations thereunder shall be automatically released (subject to the provisions of the Credit Facility).

The Credit Facility contains certain covenants including restrictions on indebtedness, and requirements with respect to leverage and interest coverage ratios; provided, however, that during an Investment Grade Period, such covenants become less restrictive on the Borrower. The Credit Facility permits distributions to the holders of the Borrower's equity interests in accordance with the cash distribution policy previously adopted by the board of directors of the general partner of the Borrower, provided that no event of default exists or would be caused thereby, and only to the extent permitted by our organizational documents. The Borrower was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2019.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly or, in the case of Eurodollar Rate Loans, at the end of the applicable interest period if shorter than six months. Interest is payable at a variable rate based on LIBOR or the base rate, determined by election at the time of borrowing, plus an applicable margin rate. Interest at the time of borrowing is determined with reference to (i) during any period that is not an Investment Grade Period, the Borrower's then-current leverage ratio and (ii) during an Investment Grade Period, with reference to the rating given to the Borrower by Moody's or Standard and Poor's. During an Investment Grade Period, the applicable margin rates are reduced by 25 basis points. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from 0.25% to 0.375% based on the leverage ratio, during a period that is not an Investment Grade Period, and 0.175% to 0.375% based on the Borrower's rating during an Investment Grade Period.

(b) 5.375% Senior Notes Due 2024

On September 13, 2016, Antero Midstream Partners and its wholly owned subsidiary, Finance Corp (together with Antero Midstream Partners, the "Issuers"), issued $650 million in aggregate principal amount of 5.375% senior notes due September 15, 2024 (the "2024 Notes") at par. The 2024 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2024 Notes are fully and unconditionally guaranteed on a joint and several senior unsecured basis by Antero Midstream Corporation, Antero Midstream Partners' wholly owned subsidiaries (other than Finance Corp) and certain of its future restricted subsidiaries. Interest on the 2024 Notes is payable on March 15 and September 15 of each year. Antero Midstream Partners may redeem all or part of the 2024 Notes at any time at redemption prices ranging from 104.031% as of September 30, 2019 to 100.00% on or after September 15, 2022. If Antero Midstream Partners undergoes a change of control followed by a rating decline, the holders of the 2024 Notes will have the right to require Antero Midstream Partners to repurchase all or a portion of the 2024 Notes at a price equal to 101% of the principal amount of the 2024 Notes, plus accrued and unpaid interest.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

(c) 5.75% Senior Notes Due 2027

On February 25, 2019, the Issuers issued $650 million in aggregate principal amount of 5.75% senior notes due March 1, 2027 (the "2027 Notes") at par. The 2027 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2027 Notes are fully and unconditionally guaranteed on a joint and several senior unsecured basis by Antero Midstream Corporation, Antero Midstream Partners' wholly owned subsidiaries (other than Finance Corp) and certain of its future restricted subsidiaries. Interest on the 2027 Notes is payable on March 1 and September 1 of each year. Antero Midstream Partners may redeem all or part of the 2027 Notes at any time on or after March 1, 2022 at redemption prices ranging from 102.875% on or after March 1, 2022 to 100.00% on or after March 1, 2025. In addition, prior to March 1, 2022, Antero Midstream Partners may redeem up to 35% of the aggregate principal amount of the 2027 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 105.75% of the principal amount of the 2027 Notes, plus accrued and unpaid interest. At any time prior to March 1, 2022, Antero Midstream Partners may also redeem the 2027 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2027 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Midstream Partners undergoes a change of control followed by a rating decline, the holders of the 2027 Notes will have the right to require Antero Midstream Partners to repurchase all or a portion of the 2027 Notes at a price equal to 101% of the principal amount of the 2027 Notes, plus accrued and unpaid interest.

(d) 5.75% Senior Notes Due 2028

On June 28, 2019, the Issuers issued $650 million in aggregate principal amount of 5.75% senior notes due January 15, 2028 (the "2028 Notes") at par. The 2028 Notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2028 Notes are fully and unconditionally guaranteed on a joint and several senior unsecured basis by Antero Midstream Corporation, Antero Midstream Partners' wholly owned subsidiaries (other than Finance Corp) and certain of its future restricted subsidiaries. Interest on the 2028 Notes is payable on January 15 and July 15 of each year. Antero Midstream Partners may redeem all or part of the 2028 Notes at any time on or after January 15, 2023 at redemption prices ranging from 102.875% on or after January 15, 2023 to 100.00% on or after January 15, 2026. In addition, prior to January 15, 2023, Antero Midstream Partners may redeem up to 35% of the aggregate principal amount of the 2028 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 105.75% of the principal amount of the 2028 Notes, plus accrued and unpaid interest. At any time prior to January 15, 2023, Antero Midstream Partners may also redeem the 2028 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2028 Notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Midstream Partners undergoes a change of control followed by a rating decline, the holders of the 2028 Notes will have the right to require Antero Midstream Partners to repurchase all or a portion of the 2028 Notes at a price equal to 101% of the principal amount of the 2028 Notes, plus accrued and unpaid interest.

(11) Accrued Liabilities

Accrued liabilities as of December 31, 2018 and 2019 consisted of the following items:

	December 31,	
(in thousands)	**2018**	**2019**
Capital expenditures	$ —	27,427
Operating expenses	—	24,980
Interest expense	—	44,440
Other	407	7,341
Total accrued liabilities	$ 407	104,188

(12) Equity-Based Compensation

The Company's general and administrative expenses include equity-based compensation costs related to the Antero Midstream GP LP Long-Term Incentive Plan ("AMGP LTIP") and the Series B Units prior to the Transactions. Equity-based compensation after the Transactions include (i) costs allocated to Antero Midstream Partners by Antero Resources for grants made prior to the Transactions pursuant to Antero Resources' long-term incentive plan, (ii) costs due to Antero Midstream Corporation LTIP (the "AMC LTIP") and (iii) the Exchanged B Units (as defined below). Antero Midstream Partners' portion of the equity-based compensation expense is included in general and administrative expenses, and recorded as a credit to the applicable classes of equity. Equity-based compensation expense allocated to Antero Midstream Partners was $4.9 million for the period from March 13, 2019 to December 31, 2019. For grants made prior to the Transactions, Antero Resources has total unamortized expense related to its various equity-based compensation plans that can be allocated to the Company of approximately $26 million as of December 31, 2019, which includes grants made under the AMP LTIP (as defined below) prior to the Transactions, which were converted into awards under the AMC LTIP. A portion of this will be allocated to Antero Midstream Partners as it is amortized over the remaining service period of the related awards. Antero Midstream Partners does not reimburse Antero Resources for noncash equity compensation allocated to it for awards issued under the Antero Resources long-term incentive plan.

Exchanged B Units

As of December 31, 2018, IDR Holdings had 98,600 Series B Units authorized and outstanding that entitled the holders to receive up to 6% of the amount of the distributions that Antero Midstream Partners made on its incentive distribution rights ("IDRs") in excess of $7.5 million per quarter, subject to certain vesting conditions. On December 31, 2018, 65,745 Series B Units were vested. The holders of vested Series B Units had the right to convert the units to common shares with a value equal to their pro rata share of up to 6% of any increase in AMGP's equity value in excess of $2.0 billion.

Upon Closing of the Transactions, each Series B Unit, vested and unvested, was exchanged for 176.0041 shares of our common stock (the "Series B Exchange"). A total of 17,353,999 shares of AMC common stock were issued in exchange for the 98,600 Series B Units then outstanding (the "Exchanged B Units"), which included 5,782,601 restricted shares of AMC common stock issued in exchange for the 32,855 unvested Series B Units.

The Company accounted for the Series B Exchange as a share-based payment modification under ASC 718, *Stock Compensation*. On March 12, 2019, which is the modification date, the Company determined the estimated fair value of the unvested Series B Unit awards using a Monte Carlo simulation using various assumptions including a floor equity value of $2.0 billion, expected volatility of 40% based on historical volatility of a peer group of publicly traded partnerships, a risk free rate of 2.51%, and expected IDR distributions based on internal estimates discounted based on a weighted average cost of capital assumption of 7.25%. Based on these assumptions, the estimated value of each Series B Unit was $1,257 when exchanged for shares of AMC common stock. 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 unvested Exchanged B Units retained the same vesting conditions as the Series B Units and vested on December 31, 2019. No awards were issued and outstanding as of December 31, 2019. Expenses related to Exchanged B Units were recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures were accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period.

The Company recognized $66 million of equity-based compensation expense related to the Series B awards, including the Series B Units prior to the Closing of the Transactions and the Exchanged B Units following the Closing of the Transactions, for the year ended December 31, 2019. For the years ended December 31, 2017 and 2018, the Company recognized $35 million and $34 million, respectively, of equity-based compensation expense related to the Series B Units. As of December 31, 2019, there is no unamortized expense related to these awards.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

AMGP LTIP

On April 17, 2017, Antero Midstream GP LP adopted the AMGP LTIP pursuant to which certain non-employee directors of Antero Midstream GP LP's general partner and certain officers, employees and consultants of Antero Resources were eligible to receive awards representing equity interests in Antero Midstream GP LP. For the years ended December 31, 2017, 2018 and 2019, the Company recognized expense of $0.2 million, $0.7 million and $0.2 million, respectively, related to these awards. Expenses related to these awards were recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures were accounted for as they occur by reversing the expense previously recognized for awards that were forfeited during the period. In connection with the Transactions, the AMGP LTIP was terminated on March 12, 2019.

AMC LTIP

Effective March, 12, 2019, the Board of Directors of Antero Midstream Corporation (the "Board") adopted the AMC LTIP under which awards may be granted to employees, directors and other service providers of the Company and its affiliates. The AMC LTIP provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, dividend equivalents, other stock-based awards, cash awards and substitute awards. The terms and conditions of the awards granted are established by the compensation committee of the Board. The Company is authorized to grant up to 15,398,901 shares of common stock to employees and directors under the AMC LTIP. As of December 31, 2019, a total of 13,596,444 shares were available for future grant under the AMC LTIP. For the year ended December 31, 2019, the Company recognized expense of $2.7 million related to these awards. Expenses related to restricted stock units are 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.

Restricted Stock Unit Awards

As part of the Transactions, each of the unvested outstanding phantom units in the Antero Midstream Partners Long Term Incentive Plan ("AMP LTIP") was assumed by Antero Midstream Corporation and converted into 1.8926 restricted stock units under the AMC LTIP representing a right to receive shares of AMC common stock for each converted phantom unit.

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

Summary Information for Restricted Stock Unit Awards

A summary of RSU awards activity during the year ended December 31, 2019 is as follows:

	Number of units	Weighted Average grant date fair value	Aggregate intrinsic value (in thousands)
Total AMC LTIP RSUs awarded and unvested—December 31, 2018	—	$ —	$ —
AMP LTIP Awards converted into AMC LTIP Awards[1]	1,068,900	$ 14.58	
Granted	729,755	$ 13.60	
Vested	(443,036)	$ 13.57	
Forfeited	(79,629)	$ 14.37	
Total AMC LTIP RSUs awarded and unvested—December 31, 2019	1,275,990	$ 14.38	$ 9,685

(1) Effective as of March 12, 2019, all unvested outstanding phantom units in the AMP LTIP were assumed by the Company and converted into restricted stock units under the AMC LTIP at a conversion rate of 1.8926 restricted stock units for each phantom unit.

Intrinsic values are based on the closing price of the Company's common shares on the referenced dates. At December 31, 2019, unamortized expense of $13 million related to the unvested RSUs is expected to be recognized over a weighted average period of approximately 2.5 years and the Company's proportionate share will be allocated to it as it is recognized.

Performance Share Unit Awards Based on Return on Invested Capital ("ROIC")

In 2019, the Company granted performance share units ("PSUs") to certain of its employees and executive officers, a portion of which vest based on the Company's actual ROIC (as defined in the award agreement) over a three-year period as compared to a targeted ROIC ("ROIC PSUs"). The number of shares of common stock that may ultimately be earned with respect to the ROIC PSUs ranges from zero to 200% of the target number of ROIC PSUs originally granted. Expense related to the ROIC 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 such expense is reversed if the likelihood of achieving the performance condition decreases.

On December 17, 2019, the compensation committee of the Board modified the terms for the ROIC PSU agreement. Accordingly, the Company accounted for the amended agreement as a share-based payment modification under ASC 718, *Stock Compensation* and revalued the awards as of the modification date. Expense for the awards are recognized on a straight-line basis over the requisite service period of the entire award. For the year ended December 31, 2019, the Company recognized $0.2 million of expense related to these awards.

Summary Information for Performance Share Unit Awards

A summary of PSU activity for the year ended December 31, 2019 is as follows:

	Number of units	Weighted Average grant date fair value
Total awarded and unvested—December 31, 2018	—	$ —
Granted	164,196	$ 6.32
Vested	—	$ —
Forfeited	(15,890)	$ 6.32
Total awarded and unvested—December 31, 2019	148,306	$ 6.32

The grant-date fair value for the ROIC PSUs is based on the closing price of the Company's common stock on the date of the modified terms for the ROIC PSU agreement, assuming the achievement of the performance condition.

As of December 31, 2019, there was $0.7 million of unamortized equity-based compensation expense related to unvested PSUs that is expected to be recognized over a weighted average period of 2.3 years.

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

(13) Cash Distributions and Dividends

The following table details the amount of distributions and dividends paid with respect to the quarter indicated (in thousands, except per share data):

Quarter and Year	Record Date	Distribution Date	Distributions/ Dividends	Antero Resources Investment	Distributions/ Dividends per share
*	May 9, 2017	September 13, 2017	$ —	15,908	*
Q2 2017	August 3, 2017	August 23, 2017	5,026	—	$ 0.027
Q3 2017	November 1, 2017	November 23, 2017	10,985	—	$ 0.059
	Total 2017		$ 16,011	15,908	
Q4 2017	February 1, 2018	February 20, 2018	$ 13,964	—	$ 0.075
Q1 2018	May 3, 2018	May 23, 2018	20,109	—	$ 0.108
Q2 2018	August 2, 2018	August 22, 2018	23,276	—	$ 0.125
Q3 2018	November 2, 2018	November 21, 2018	26,817	—	$ 0.144
	Total 2018		$ 84,166	—	
Q4 2018	February 1, 2019	February 21, 2019	$ 30,543	—	$ 0.164
Q1 2019	April 26, 2019	May 8, 2019	152,082	—	$ 0.3025
Q1 2019	May 15, 2019	May 15, 2019	98	—	**
Q2 2019	July 26, 2019	August 7, 2019	154,146	—	$ 0.3075
Q2 2019	August 14, 2019	September 18, 2019	138	—	**
Q3 2019	November 1, 2019	November 13, 2019	153,033	—	$ 0.3075
Q3 2019	November 14, 2019	November 14, 2019	138	—	**
***	December 31, 2019	December 31, 2019	2,299	—	***
	Total 2019		$ 492,477	—	

* Income relating to periods prior to May 9, 2017, the closing of our IPO, was distributed to Antero Investment prior to its liquidation.

** Dividends are paid in accordance with the terms of the Series A Preferred Stock as discussed in Note 14—Equity and Earnings Per Common Share.

*** Distributions declared on unvested Series B Units prior to the closing date of the Transactions that were paid upon the vesting date to the holders of the Exchanged B Units.

On January 15, 2020, the Board declared a cash dividend on the shares of AMC common stock of $0.3075 per share for the quarter ended December 31, 2019. The dividend will be payable on February 12, 2020 to stockholders of record as of January 31, 2020. The Company pays dividends (1) out of surplus or (2) if there is no surplus, out of the net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year, as provided under Delaware law.

The Board also declared a cash dividend of $138 thousand on the shares of Series A Preferred Stock of Antero Midstream Corporation to be paid on February 14, 2020 in accordance with the terms of the Series A Preferred Stock, which are discussed in Note 14—Equity and Earnings Per Common Share. As of December 31, 2019, there were dividends in the amount of $69 thousand accumulated in arrears on the Company's Series A Preferred Stock.

(14) Equity and Earnings Per Common Share

(a) Preferred Stock

The Board authorized 100,000,000 shares of preferred stock in connection with the closing of the Transactions (see Note 3—Business Combination) on March 12, 2019, and issued 10,000 shares of preferred stock designated as "5.5% Series A Non-Voting Perpetual Preferred Stock" (the "Series A Preferred Stock"), to The Antero Foundation on that date. Dividends on the Series A

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

Preferred Stock are cumulative from the date of original issue and payable in cash on the 45th day following the end of each fiscal quarter, or such other dates as the Board will approve, at a rate of 5.5% per annum on (i) the liquidation preference per share of Series A Preferred Stock (as described below) and (ii) the amount of accrued and unpaid dividends for any prior dividend period on such share of Series A Preferred Stock, if any. At any time following the date of issue, in the event of a change of control, or at any time on or after March 12, 2029, the Company may redeem the Series A Preferred Stock at a price equal to $1,000 per share, plus any accrued and unpaid dividends, payable in cash; provided that if any shares of the Series A Preferred Stock are held by The Antero Foundation at the time of such redemption, the price for redemption of each share of Series A Preferred Stock will be the greater of (i) $1,000 per share, plus any accrued but unpaid dividends, and (ii) the fair market value of the Series A Preferred Stock. On or after March 12, 2029, the holder of each share of Series A Preferred Stock (other than The Antero Foundation) may convert such shares, at any time and from time to time, at the option of the holder into a number of shares of AMC common stock equal to the conversion ratio in effect on the applicable conversion date, subject to certain limitations. The Series A Preferred Stock ranks senior to the AMC common stock as to dividend rights, as well as with respect to rights upon liquidation, winding-up or dissolution of the Company. Holders of the Series A Preferred Stock do not have any voting rights in the Company, except as required by law, or any preemptive rights.

(b) Weighted Average Shares Outstanding

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

	Year Ended December 31,		
(in thousands)	**2017**	**2018**	**2019**
Basic weighted average number of shares outstanding	186,176	186,203	442,640
Add: Dilutive effect of restricted stock units	—	—	—
Add: Dilutive effect of Series A preferred stock	—	—	—
Diluted weighted average number of shares outstanding	186,176	186,203	442,640
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings per common share[(1)]:			
Restricted stock units	—	—	53
Preferred shares	—	—	1,318

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

(c) Earnings Per Common Share

Earnings per common share—basic for (i) the years ended December 31, 2017 and 2018 is computed by dividing net income attributable to AMGP by the basic weighted average number of common shares representing limited partner interest in AMGP outstanding during the period and (ii) the year ended December 31, 2019 is computed by dividing net income (loss) attributable to Antero Midstream Corporation by the basic weighted average number of shares of AMC common stock outstanding during the period. Earnings 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. During periods in which the Company incurs a net loss, diluted weighted average shares outstanding are equal to basic weighted average shares outstanding because the effect of all equity awards is anti-dilutive.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

	Year Ended December 31,		
(in thousands, except per share amounts)	2017	2018	2019
Net income (loss)	$ 2,325	66,608	(355,114)
Pre-IPO net income attributed to parent	4,939	—	—
Less net income attributable to Series B Units	(784)	(5,236)	—
Less preferred stock dividends	—	—	(442)
Net income (loss) available to common shareholders	$ 6,480	61,372	(355,556)
Net income (loss) per share–basic and diluted	$ 0.03	0.33	(0.80)
Weighted average common shares outstanding–basic	186,176	186,203	442,640
Weighted average common shares outstanding–diluted	186,176	186,203	442,640

(15) Fair Value Measurement

Business Combination

As the Transactions were accounted for under the acquisition method of accounting, the Company estimated the fair value of assets acquired and liabilities assumed at March 12, 2019. See Note 3—Business Combination. In connection with the Transactions, the Company, among other things, issued shares of common stock valued at the closing market price of the common shares at the effective time of the Transactions, which was a Level 1 measurement.

The Company used the discounted cash flow approach, which is an income statement technique, to estimate the fair value of the customer relationships and investments in unconsolidated affiliates using a weighted-average cost of capital of 14.1% as of March 12, 2019, which is based on significant inputs not observable in the market, and thus represents a Level 3 measurement within the fair value hierarchy. The Company also used this approach in combination with the cost approach to estimate the fair value of property and equipment whereby certain property and equipment was adjusted for recent purchases of similar items, economic and functional obsolescence, location, normal useful lives, and capacity (if applicable). To estimate the fair value of the long-term debt, the Company used Level 2 market data inputs.

Goodwill

The Company estimated the fair value of its assets in performing its annual goodwill analysis. The Company utilized a combination of approaches to discounted cash flow approach, comparable company method and the cost approach, whereby certain property and equipment was adjusted for recent purchases of similar items, economic and functional obsolescence, location, normal useful lives, and capacity (if applicable). The Company performed its fourth quarter quantitative analysis using a weighted-average cost of capital of 10.0% as of December 31, 2019, which is based on significant inputs not observable in the market, and thus represents a Level 3 measurement within the fair value hierarchy.

Contingent Acquisition Consideration

In connection with Antero Resources' contribution of Antero Water and certain water handling assets to Antero Midstream Partners in September 2015 (the "Water Acquisition"), Antero Midstream Partners agreed to pay Antero Resources (a) $125 million in cash if Antero Midstream Partners delivered 176,295,000 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 Partners delivers 219,200,000 barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. This contingent consideration liability is valued based on Level 3 inputs related to expected average volumes and weighted average cost of capital.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

The following table provides a reconciliation of changes in Level 3 financial liabilities measured at fair value on a recurring basis for the period shown below (in thousands):

Contingent acquisition consideration—December 31, 2018	$	—
Contingent acquisition consideration assumed from Antero Midstream Partners		116,924
Accretion and change in fair value of contingent acquisition consideration		8,076
Contingent acquisition consideration—December 31, 2019	$	125,000

The Company accounts for contingent consideration in accordance with applicable accounting guidance pertaining to business combinations. Antero Midstream Partners is contractually obligated to pay Antero Resources contingent consideration in connection with the Water Acquisition. The Company updates its assumptions each reporting period based on new developments and adjusts such amounts to fair value based on revised assumptions, if applicable, until such consideration is satisfied through payment upon achievement of the specified objectives or it is eliminated upon failure to achieve the specified objectives.

As of December 31, 2019, Antero Midstream Partners had delivered more than 176,295,000 barrels of fresh water during the period between January 1, 2017 and December 31, 2019. As a result, Antero Midstream Partners paid Antero Resources $125 million in January 2020. The Company does not expect to pay for the contingent consideration for delivery of 219,200,000 barrels or more barrels of fresh water during the period between January 1, 2018 and December 31, 2020 based on Antero Resources' disclosed 2020 budget. 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 liability associated with future milestone payments was based on the risk adjusted present value of the contingent consideration payout.

Senior Unsecured Notes

As of December 31, 2019 the fair value of the Company's 2024 Notes, 2027 Notes and 2028 Notes was approximately $603 million, $571 million and $569 million, respectively, based on Level 2 market data inputs.

Other Assets and Liabilities

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

(16) Investments in Unconsolidated Affiliates

Investment in Antero Midstream Partners

Prior to the closing of the Transactions, AMGP did not consolidate Antero Midstream Partners, and AMGP's share of Antero Midstream Partners' earnings as a result of AMGP's ownership of the IDRs was accounted for using the equity method of accounting. AMGP recognized distributions earned from Antero Midstream Partners as "Equity in earnings of unconsolidated affiliates" on its statement of operations in the period in which they were earned and were allocated to AMGP's capital account. AMGP's long-term interest in the IDRs on the balance sheet is recorded in "Investment in unconsolidated affiliates." The ownership of the general partner interests and IDRs did not provide AMGP with any claim to the assets of AMGP other than the balance in its Antero Midstream Partners capital account. Income related to the IDRs was recognized as earned and increased AMGP's capital account and equity investment. When these distributions were paid to AMGP, they reduced its capital account and its equity investment in Antero Midstream Partners. As a result of the Transactions, Antero Midstream Corporation assumed financial control of Antero Midstream Partners and Antero Midstream Partners is now consolidated (see Note 3—Business Combination).

Investment in Stonewall and MarkWest Joint Venture

The Company has a 15% equity interest in the gathering system of Stonewall, which operates a 67-mile pipeline on which Antero Resources is an anchor shipper.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

Antero Midstream Partners has a 50% equity interest in the Joint Venture to develop processing and fractionation assets with MarkWest, a wholly owned subsidiary of MPLX, LP. The Joint Venture was formed to develop processing and fractionation assets in Appalachia. MarkWest operates the Joint Venture assets, which consist of processing plants in West Virginia and a one-third interest in two MarkWest fractionators in Ohio.

The Company's net income (loss) includes its proportionate share of the net income of the Joint Venture and Stonewall. When the Company records its proportionate share of net income, it increases equity income in the consolidated statements of operations and comprehensive income and the carrying value of that investment on its balance sheet. When distributions on the Company's proportionate share of net income are received, they are recorded as reductions to the carrying value of the investment on the balance sheet and are classified as cash inflows from operating activities in accordance with the nature of the distribution approach under ASU No. 2016-15. The Company uses the equity method of accounting to account for its investments in Stonewall and the Joint Venture because it 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 its ownership interest, representation on the applicable board of directors and participation in policy-making decisions of Stonewall and the Joint Venture.

The following table is a reconciliation of our investments in these unconsolidated affiliates:

(in thousands)	Antero Midstream Partners LP	Stonewall	MarkWest Joint Venture	Total Investment in Unconsolidated Affiliates
Balance at December 31, 2017	23,772	—	—	23,772
Equity in net income of unconsolidated affiliates	142,906	—	—	142,906
Distributions from unconsolidated affiliates	(123,186)	—	—	(123,186)
Balance at December 31, 2018	43,492	—	—	43,492
Distributions from unconsolidated affiliates	(43,492)	—	—	(43,492)
Balance at March 12, 2019	—	—	—	—
Investments in unconsolidated affiliates acquired from Antero Midstream Partners	—	142,071	426,214	568,285
Additional investments	—	—	154,359	154,359
Equity in net income of unconsolidated affiliates[1]	—	4,117	47,198	51,315
Distributions from unconsolidated affiliates	—	(5,730)	(58,590)	(64,320)
Balance at December 31, 2019	$ —	140,458	569,181	709,639

(1) As adjusted for the amortization of the difference between the cost of the equity investments in Stonewall and the Joint Venture and the amount of the underlying equity in the net assets of Stonewall and the Joint Venture as of the date of the acquisition of Antero Midstream Partners.

(b) Summarized Financial Information of Unconsolidated Affiliates

The following tables present summarized financial information for the Company's investments in unconsolidated affiliates.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

Combined Balance Sheets

(in thousands)	December 31, 2018	December 31, 2019
Current assets	$ 90,481	$ 61,641
Noncurrent assets	1,327,947	1,660,401
Total assets	$ 1,418,428	$ 1,722,042
Current liabilities	$ 76,605	$ 33,912
Noncurrent liabilities	6,986	5,521
Noncontrolling interest	172,865	175,021
Partners' capital	1,161,972	1,507,588
Total liabilities and partners' capital	$ 1,418,428	$ 1,722,042

Statements of Combined Operations

(in thousands)	Year Ended December 31, 2017	2018	2019
Revenues	$ 119,371	189,222	254,868
Operating expenses	40,059	75,250	105,218
Income from operations	79,312	113,972	149,650
Net income attributable to the equity method investments	88,717	131,626	23,615

(17) Reporting Segments

Prior to the closing of the Transactions, AMGP had no reporting segment results. Following the completion of the Transactions, the Company's operations, which are located in the United States, are organized into two reporting segments: (1) gathering and processing and (2) water handling.

Gathering and Processing

The gathering and processing segment includes a network of gathering pipelines and compressor stations that collect and process production from Antero Resources' wells in West Virginia and Ohio. The gathering and processing segment also includes equity in earnings from the Company's investments in the Joint Venture and Stonewall.

Water Handling

The Company's water handling segment includes two independent systems that deliver fresh water from sources including the Ohio River, local reservoirs and several regional waterways. The water handling segment also includes the Clearwater Facility that was placed in service in 2018 and idled in September 2019 (See Note 4—Clearwater Facility Impairment), as well as other fluid handling services, which includes high rate transfer, wastewater transportation, disposal and treatment. See Note 8—Property and Equipment.

These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for these operations. Management evaluates the performance of the Company's business segments based on operating income. Interest expense is primarily managed and evaluated on a consolidated basis.

ANTERO MIDSTREAM CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

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

	Gathering and Processing	Water Handling	Unallocated [1]	Consolidated Total
Year ended December 31, 2019				
Revenues:				
Revenue–Antero Resources	$ 543,538	306,010	—	849,548
Revenue–third-party	—	50	—	50
Amortization of customer relationships	(29,850)	(27,160)	—	(57,010)
Total revenues	513,688	278,900	—	792,588
Operating expenses:				
Direct operating	41,546	154,272	—	195,818
General and administrative (excluding equity-based compensation)	20,660	10,898	13,038	44,596
Facility idling	—	11,401	—	11,401
Equity-based compensation	5,561	2,130	65,826	73,517
Impairment of property and equipment	592	409,147	—	409,739
Impairment of goodwill	—	340,350	—	340,350
Impairment of customer relationships	—	11,871	—	11,871
Depreciation	39,652	55,874	—	95,526
Accretion and change in fair value of contingent acquisition consideration	—	8,076	—	8,076
Accretion of asset retirement obligations	—	187	—	187
Total expenses	108,011	1,004,206	78,864	1,191,081
Operating income (loss)	$ 405,677	(725,306)	(78,864)	(398,493)
Equity in earnings of unconsolidated affiliates	$ 51,315	—	—	51,315
Total assets	$ 4,891,114	1,287,245	104,519	6,282,878
Additions to property and equipment, net	$ 267,383	124,607	—	391,990

[1] Certain expenses that are not directly attributable to gathering and processing and water handling are managed and evaluated on a consolidated basis.

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Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2017, 2018, and 2019

(18) Quarterly Financial Information (Unaudited)

The Company's quarterly consolidated unaudited financial information for the years ended December 31, 2018 and 2019 is summarized in the table below (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2018				
Total income	$ 28,453	33,145	37,816	43,492
Total operating expenses	9,560	11,509	10,803	11,979
Net income and comprehensive income	12,805	14,387	18,028	21,388
Net income attributable to Series B units	(413)	(506)	(598)	(3,719)
Net income attributable to common shareholders	12,392	13,881	17,430	17,669
Net income per common share–basic and diluted	$ 0.07	0.07	0.09	0.10
Year ended December 31, 2019				
Total operating revenues	$ 54,108	255,618	243,795	239,067
Total operating expenses	43,500	138,027	577,884	431,670
Operating income (loss)	10,608	117,591	(334,089)	(192,603)
Net income (loss) and comprehensive income (loss)	9,648	69,274	(289,477)	(144,559)
Net income (loss) per common share–basic and diluted	$ 0.04	0.14	(0.57)	(0.29)