Antero Resources

ANTERO RESOURCES | 2016 ANNUAL REPORT

ANTERO RESOURCES
corporate profile

$1.5
BILLION
LTM EBITDAX

1,847 MMcfe/d
NET PRODUCTION

25% LIQUIDS
NATURAL GAS 75%

3,630
UNDRILLED
LOCATIONS

3P RESERVES
46.4 Tcfe

NET ACRES
616,000

59% AM[1]
OWNERSHIP

AR
LISTED
NYSE

Cover photo:
Antero Resources and its group contributed $1 million to the preservation of West Virginia's Cheat Canyon in 2014. The preservation and protection of the natural environment is a core principle of Antero Resources. Photography by Kent Mason.

Footnotes:
(1) Antero Midstream (NYSE: AM)

PEER LEADING REALIZATIONS
supported by firm transportation and hedging

AR REALIZATIONS vs GAS PRICES

KEY DRIVERS BEHIND LONG-TERM OUTLOOK

DEEP DRILLING
INVENTORY

STRONG WELL
PERFORMANCE

IMPROVING
CAPITAL
EFFICIENCY

VISIBLE,
ATTRACTIVE
PRICE REALIZATIONS

SIGNIFICANT CASH FLOW GROWTH
& DECLINING LEVERAGE PROFILE

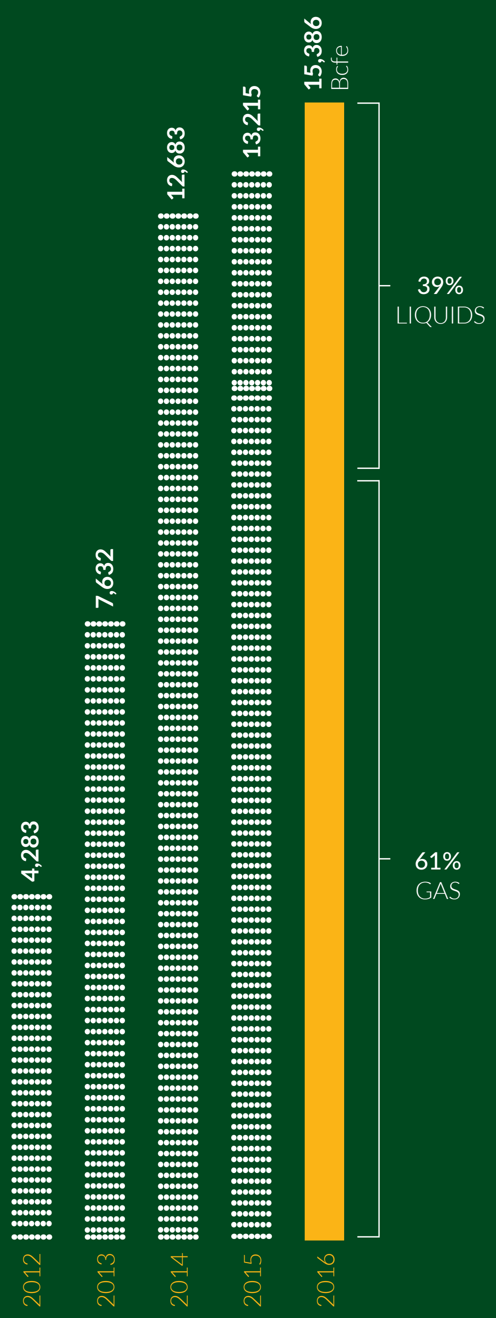
SOLID BALANCE SHEET
WITH **ABUNDANT LIQUIDITY**

Strong **RESERVE**, **PRODUCTION** and **CASH FLOW** growth

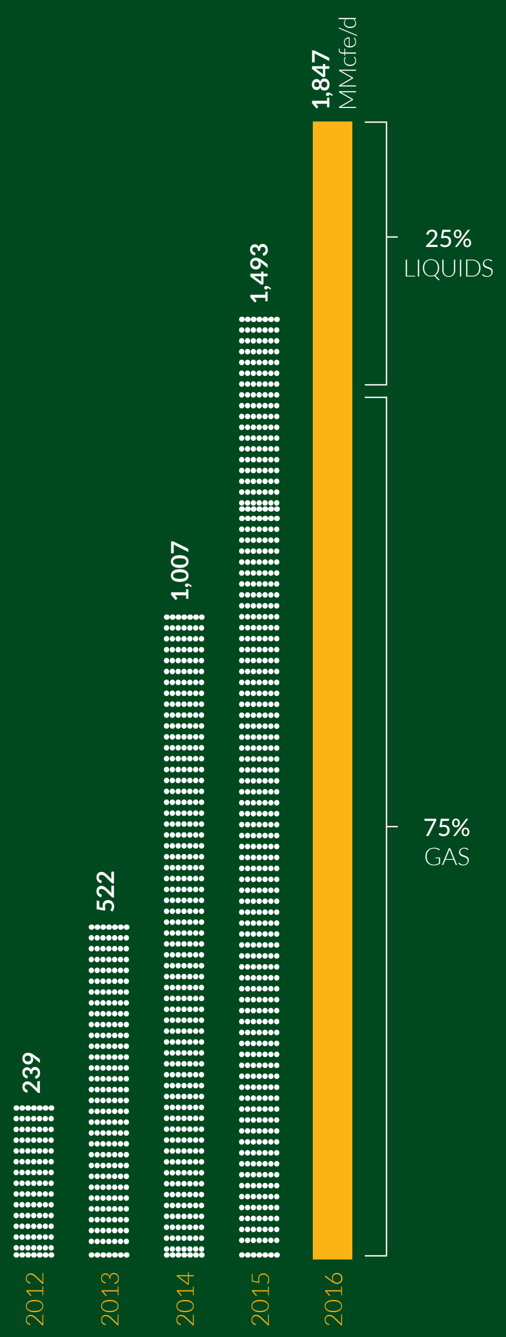
Leading ACREAGE position in the core

of the Marcellus and Utica Shale plays

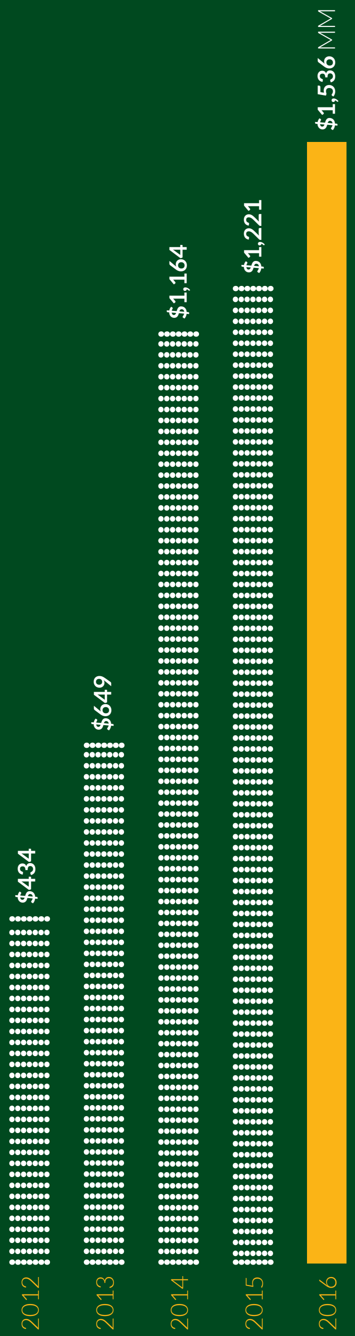
PROVED RESERVES (Bcfe)



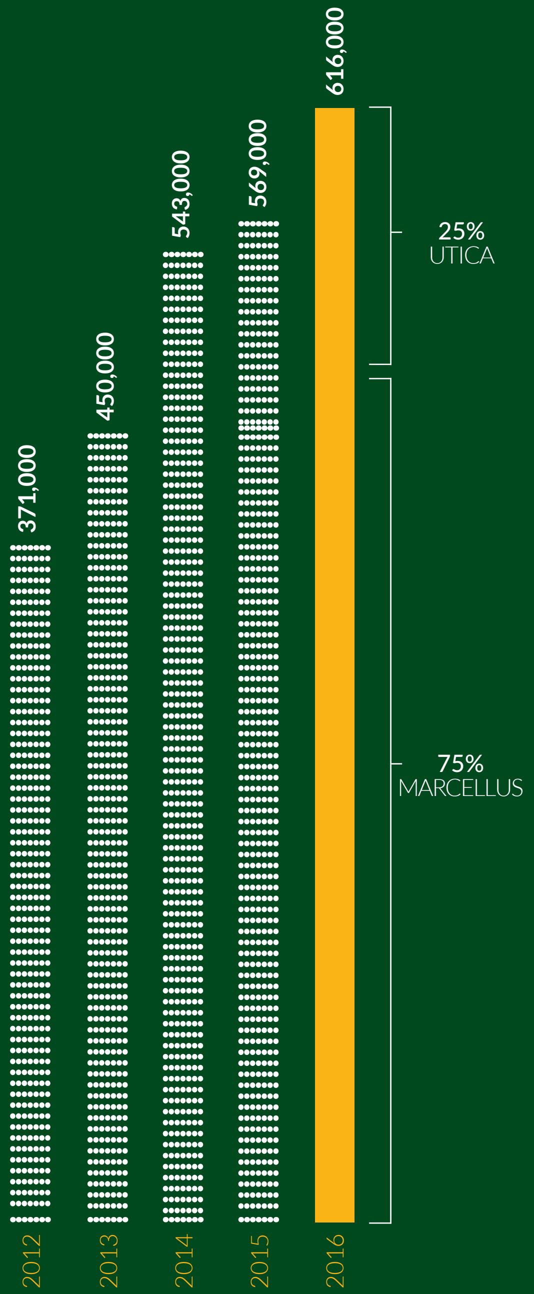
PRODUCTION (MMcfe/d)



EBITDAX ($MM)



NET ACREAGE



DEAR FELLOW SHAREHOLDERS,

Antero Resources (NYSE: AR) delivered another remarkable year of performance in 2016. We strengthened our position in the liquids-rich acreage core of the Marcellus and Utica Shale plays in the Appalachian Basin. Net proved reserves grew by 16% to 15.4 Tcfe, production grew by 24% to 1,847 MMcfe/d, including 78,000 Bbl/d of liquids, and EBITDAX grew by 26% to $1.5 billion. Looking ahead through 2020, we have planned our drilling and completion capital program to stay within consolidated operating cash flow assuming current strip pricing. We have targeted production growth in excess of 20% while de-leveraging the balance sheet. Our future production growth is supported by our 616,000 net acreage position which represents 3,630 gross undrilled locations. Seventy percent of these locations generate a return of 20% at less than $3.00/Mcf NYMEX gas pricing. To ensure long-term favorable price realizations, we have built an industry-leading natural gas hedge position at prices well above current futures market prices and a firm transport portfolio that sends our gas to favorable markets dominated by Gulf Coast pricing. We look forward to achieving our growth targets and delivering share price appreciation to our investors into 2017.

MARCELLUS SHALE DEVELOPMENT

Antero Resources was the most active operator in the Marcellus play with an average of seven rigs running during the year. We turned 88 wells to sales which led to a 15% increase in production to 1,335 MMcfe/d, including 59,000 Bbl/d of liquids. We achieved a 29% reduction in well costs due to fewer drilling and completion days per well and reduced service costs. In addition, we increased our Marcellus wellhead recoveries by 18% to 2.0 Bcf/1,000 feet of lateral through bigger completions reflecting increased proppant and water volumes. Excited by these increased recoveries, we expanded our core acreage position by 42,000 net acres through strategic acquisitions and leasing. Our 2016 development plan and net acreage additions enabled the Company to grow our proved and combined 3P reserves to 13.4 Tcfe and 39.6 Tcfe, respectively. Reduced drilling and completion costs as well as improved recoveries yielded much better well economics. All of our development activity in 2016 was focused on the liquids-rich portion of our acreage with impressive results. At year-end 2016, the Sherwood processing complex had rich-gas processing capacity of 1.2 Bcf/d, including a 40,000 Bbl/d de-ethanizer. In the coming year we expect the addition of two more 200 MMcf/d processing units to further support the growth of our liquids-rich gas production.

UTICA SHALE GROWTH

We continued to enhance and expand our Utica operations in 2016. Forty wells were turned to sales, contributing to a 54% increase in production to 512 MMcfe/d, including 19,000 Bbl/d of liquids. We achieved a 27% reduction in well costs due to reduced drilling and completion days per well and reduced service costs. We upgraded our core net acreage position by 5,000 net acres through a combination of acquisitions, base leasing and land trades. With 800 MMcf/d of processing capacity now in place at the Seneca processing complex, we continue to execute our development plan with three rigs budgeted for 2017. The lack of incremental takeaway capacity to premium-priced markets will keep the Utica's activity in the year ahead similar to 2016 levels. However, we project a significant increase in 2018 when the Rover pipeline is expected to be fully in-service which will enable us to send greater volumes to the attractively-priced Chicago and Gulf Coast markets.

FUTURE READY

Our continued success in 2016 reinforces the reputation of Antero Resources as a world-class operator and industry leader in the Appalachian Basin. We enter 2017 focused on maintaining our peer-leading production growth through enhanced completions and concentrating on the liquids-rich regimes that drive the highest returns. In light of the increasing capital efficiencies achieved in 2016, we held our 2017 capital budget at the 2016 levels while forecasting expected production growth of nearly 20%. This level of capital spending maintains our momentum for long-term value creation while simultaneously strengthening the balance sheet. In addition to the Rover pipeline, the Mariner East 2 NGL pipeline to Marcus Hook is expected to be placed in-service in late 2017. The Mariner East pipeline will boost our NGL takeaway capacity and liquids price realizations as we move into 2018 by delivering NGLs to the Marcus Hook terminal for export to international markets. We continue to monitor our core areas for additional expansion opportunities in both the upstream and midstream businesses, and remain focused on growth and sustainable value creation into 2020 and beyond.

"We enter 2017 focused on maintaining our peer-leading production growth through enhanced completions and concentrating on the liquids-rich regimes that drive the highest returns.

ANTERO MIDSTREAM EXPANSION

Antero Midstream is an integrated midstream service provider whose primary role is to support the growth of Antero Resources in Appalachia. Through its gathering and compression assets, Antero Midstream provides low-pressure gathering, compression and high-pressure gathering services for Antero Resources. Antero Midstream also manages fresh water as well as flowback and produced water services for Antero Resources through its fluid handling network. This network will continue to contribute to growth and profitability in the years to come. In addition, the completion of the Antero Clearwater facility in late 2017 will position Antero Midstream at the forefront of water management and conservation among U.S. shale producers. The Antero Clearwater facility will enhance our environmental and local community support goals by reducing water truck traffic by 10 million miles annually and cutting greenhouse gas emissions by more than 30,000 tons per year. Antero Midstream continued to expand its position on the midstream value chain in 2016 by exercising its right to acquire a 15% non-operated equity interest in the 1.4 Bcf/d, 67-mile Stonewall Pipeline on which Antero Resources is an anchor shipper. Value chain diversification was further achieved in February 2017 when the Partnership announced an $800 million processing and fractionation joint venture with MarkWest Energy Partners, a subsidiary of MPLX LP. Overall, 2016 was another year of continued growth and value chain buildout for Antero Midstream.

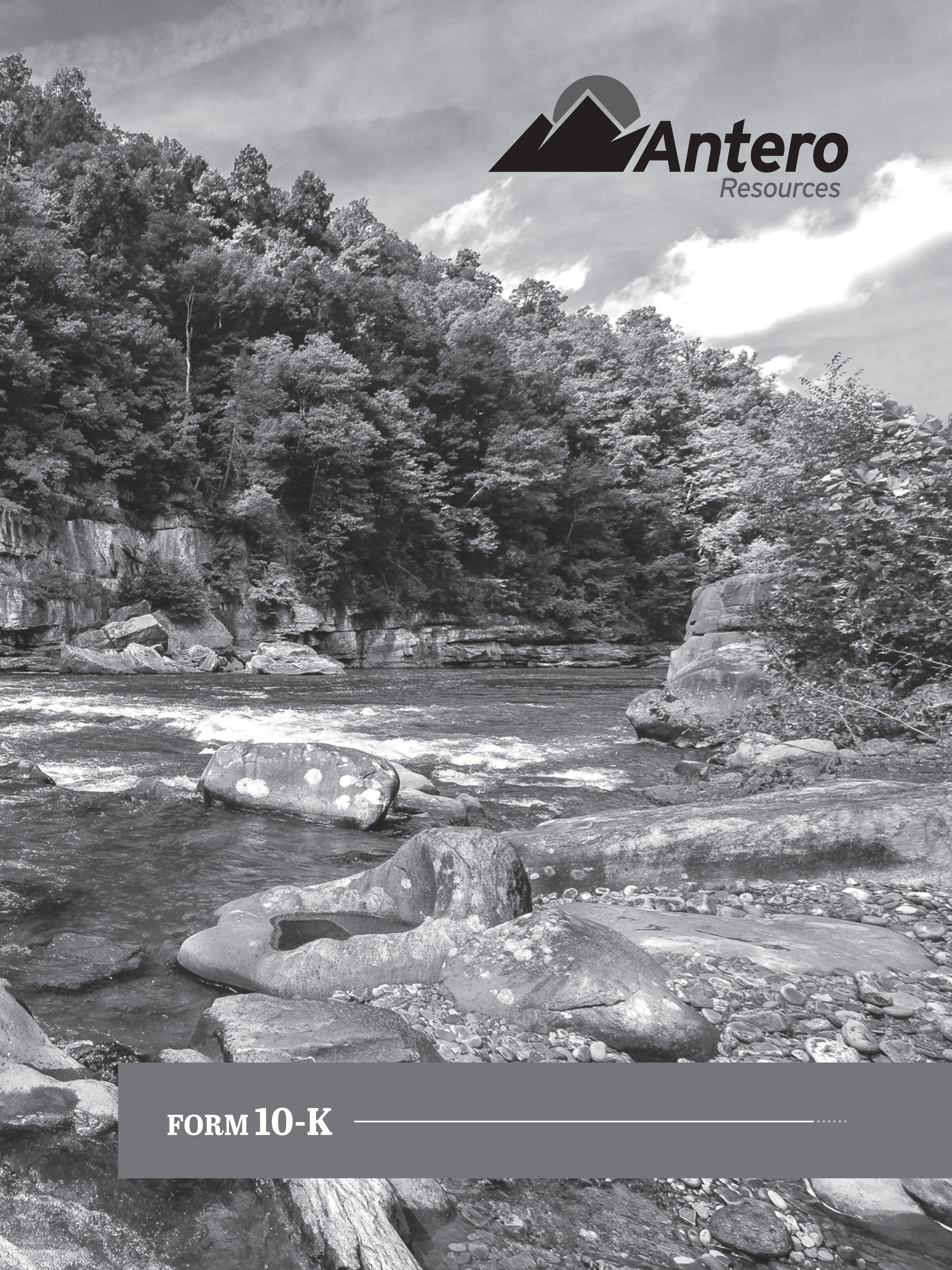
THE PEOPLE OF ANTERO

We want to express our appreciation for the hard work and dedication of our talented employees. The people of Antero Resources generate value creation and momentum year after year in what has been a difficult market environment. Their skills and expertise in assembling and executing world-class projects represent the true strength and competitive advantage of Antero Resources. We are also grateful for the guidance and support of our Board of Directors. We thank you, our shareholders, for investing in our Company and look forward to continued success in 2017, and for many years to come.

Paul M Rady

PAUL M. RADY
Chairman, CEO
and Co-founder

GLEN C. WARREN, JR.
President, CFO, Director
and Co-founder



Antero
Resources

FORM 10-K

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, 2016

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	Name of Each Exchange on which Registered
Common Stock, Par Value $0.01 Per Share	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $4.6 billion based on the closing price of Antero Resources Corporation's common stock as reported on that day on the New York Stock Exchange of $25.98.

The registrant had 315,006,448 shares of common stock outstanding as of February 23, 2017.

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

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report on Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended 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 forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" in this Annual Report on Form 10-K. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity, and capital required for our development program;
- natural gas, natural gas liquids ("NGLs"), and oil prices;
- timing and amount of future production of natural gas, NGLs, and oil;
- hedging strategy and results;
- ability to realize the anticipated benefits of Antero Midstream's recently announced processing and fractionation joint venture with MarkWest Energy Partners, L.P.;
- ability to meet our minimum volume commitments and to utilize or monetize our firm transportation commitments;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs, and oil;
- leasehold or business acquisitions;
- costs of developing our properties;
- operations of Antero Midstream Partners LP;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering, processing, transportation, and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price volatility and low commodity prices, inflation, availability of drilling and production equipment and services, environmental risks, drilling 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 flow and access to capital, the timing of development expenditures, 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 price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities, or changes in commodity prices, may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs, and oil that are ultimately recovered.

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

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

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

GLOSSARY OF OIL AND NATURAL GAS 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:

"*100% success rate*." Antero defines the term "100% success rate" to mean that all wells were completed and produce in commercially viable quantities.

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

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

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

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

"*Btu*." British thermal unit.

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

"C4+": Natural gas liquids excluding ethane and propane, consisting primarily of isobutane, normal butane, and natural gasoline.

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

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

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

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

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

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

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

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

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

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

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

"*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.

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

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

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

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

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

"MMcfe/d." MMcfe per day.

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

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

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

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

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

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

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

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

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

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

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

"*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.

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

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

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

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

PART I

Items 1 and 2. Business and Properties

Our Company

Antero Resources Corporation ("Antero") is an independent oil and natural gas company engaged in the exploration, development, production, and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2016, we held approximately 616,000 net acres of oil and gas properties located in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. Our corporate headquarters are in Denver, Colorado.

Antero's consolidated subsidiary, Antero Midstream Partners LP ("Antero Midstream") is a public master limited partnership which owns, operates, and develops midstream energy infrastructure primarily to service Antero's production and completion activity. Antero's consolidated financial statements include Antero Midstream's financial position and results of operations.

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, 2016					Three months ended December 31, 2016
	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	13,355	$ 3,236	534	464,000	2,923	1,514
Ohio Utica Shale	2,031	$ 440	140	152,000	707	476
Total	15,386	$ 3,676	674	616,000	3,630	1,990

(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, 2016, which were $2.31 per MMBtu for natural gas based on a $2.46 per MMBtu NYMEX reference price, $13.58 per Bbl for NGLs and $32.63 per Bbl for oil for the Appalachian Basin based on a $42.68 per Bbl WTI reference price.

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

(3) Does not include certain vertical wells that were primarily acquired in conjunction with leasehold acreage acquisitions.

(4) 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. From 2008 through December 31, 2016, our drilling operations in the Appalachian Basin have had a 100% success rate. We have 3,630 potential horizontal well locations on our existing leasehold acreage within our proved, probable, and possible reserve categories.

We have secured sufficient long-term firm takeaway capacity on major pipelines that are in existence or currently under construction 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) gathering and processing, (iii) water handling and treatment, and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States. Financial information for our industry segment operations is located under "Note 16: Segment Information."

2016 and Recent Developments and Highlights

Energy Industry Environment

In late 2014, global energy commodity prices declined precipitously as a result of several factors, including an increase in worldwide commodity supplies, a stronger U.S. dollar, relatively mild weather in large portions of the U.S. during the 2014 and 2015 winter months, and strong competition among oil producing countries for market share. Depressed commodity prices continued into 2015 and 2016, although a modest recovery has occurred in late 2016 and early 2017.

Spot prices for WTI declined significantly since June 2014 levels of approximately $106.00 per Bbl and have ranged from less than $30.00 per Bbl in February 2016 to approximately $53.00 per Bbl in February 2017. Spot prices for Henry Hub natural gas also declined significantly from approximately $4.40 per MMBtu in January 2014 to $2.00 per MMBtu in March 2016. Natural gas prices have recently recovered to approximately $3.00 per MMBtu in February 2017 due to increases in demand as a result of colder winter weather in many regions of the United States. Spot prices for propane, which is the largest portion of our NGLs sales, declined from approximately $1.55 per gallon in January 2014 to less than $0.35 per gallon in January 2016. Prices for propane have recovered to over $0.70 per gallon in February 2017.

In response to these market conditions and concerns about access to capital markets, many U.S. exploration and development companies significantly reduced their capital spending in 2015 and 2016. Our capital spending for drilling, completions, and land for 2016 was $2.1 billion, including drilling and completion costs of $1.3 billion and leasehold additions of $153 million, and acquisition costs of $593 million. Excluding acquisitions, this represents a decrease of 20% from our 2015 capital expenditures and a decrease of 52% from our 2014 capital expenditures. Although commodity prices have decreased in recent years, we have also experienced reductions in drilling and development costs as a result of decreased demand for oilfield services and increased efficiencies from improved drilling and completion technology and procedures. In addition to the reduction in our capital expenditures during 2016, we deferred the completion of 40 wells.

Reserves, Production, and Financial Results

As of December 31, 2016, our estimated proved reserves were 15.4 Tcfe, consisting of 9.4 Tcf of natural gas, 554 MMBbl of ethane, 404 MMBbl of C3+ NGLs, and 38 MMBbl of oil. As of December 31, 2016, 61% of our estimated proved reserves by volume were natural gas, 37% were NGLs, and 2% were oil. Proved developed reserves were 6.9 Tcfe, or 45% of total proved reserves.

For the year ended December 31, 2016, our production totaled 676 Bcfe, or 1,847 MMcfe per day, a 24% increase compared to 545 Bcfe, or 1,493 MMcfe per day, for the year ended December 31, 2015. The average price received for 2016 production before the effects of gains on settled derivatives was $2.60 per Mcfe compared to $2.52 per Mcfe in 2015. The increase was primarily attributable to increases in energy commodity prices during the second half of 2016. Our average realized price after the effects of gains on settled derivatives was $4.08 per Mcfe during 2016 as compared to $4.10 per Mcfe during 2015.

For the year ended December 31, 2016, we generated consolidated cash flow from operations of $1.24 billion, a consolidated net loss of $849 million, and Adjusted EBITDAX of $1.54 billion. This compares to consolidated cash flow from operations of $1.02 billion, consolidated net income of $941 million, and Adjusted EBITDAX of $1.22 billion for the year ended December 31, 2015. 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).

The consolidated net loss for 2016 included (i) commodity derivative fair value losses of $514 million, comprised of gains on settled derivatives of $1.0 billion and a non-cash loss of $1.5 billion on changes in the fair value of commodity derivatives, (ii) a noncash charge of $102 million for equity-based compensation, (iii) a noncash charge of $163 million for impairments of unproved properties, and (iv) a noncash tax benefit of $496 million.

2016 Capital Spending and 2017 Capital Budgets

For the year ended December 31, 2016, our total consolidated capital expenditures were approximately $2.5 billion, including drilling and completion expenditures of $1.3 billion, leasehold additions of $153 million, acquisitions of $593 million, gathering and compression expenditures of $231 million, water handling and treatment expenditures of $188 million, and other capital expenditures of $3 million. Our consolidated capital budget for 2017 is $2.3 billion, and includes: $1.3 billion for drilling and completion, $200 million for core leasehold acreage additions and extensions, and $800 million for capital expenditures by Antero Midstream. We do not budget for acquisitions. Approximately 70% of the drilling and completion budget is allocated to the Marcellus Shale and the remaining 30% is allocated to the Utica Shale. During 2017, we plan to operate an average of four drilling rigs in the Marcellus Shale and three drilling rigs in the Utica Shale, and we plan to complete 170 horizontal wells in the Marcellus and Utica Shales in 2017 as compared to 140 in 2016. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Hedge Position

At December 31, 2016, we had entered into fixed price hedging contracts for January 1, 2017 through December 31, 2022 for 3.3 Tcf of natural gas at a weighted average index price of $3.66 per MMBtu, 452 million gallons of propane at a weighted average price of $0.41 per gallon, 307 million gallons of ethane at a weighted average price of $0.25 per gallon, and 1.1 million Bbls of oil at a weighted average price of $54.75 per Bbl. These hedging contracts include contracts for the year ending December 31, 2017 of 679 Bcf of natural gas at a weighted average index price of $3.63 per MMBtu, 422 million gallons of propane at a weighted average price of $0.39 per gallon, 307 million gallons of ethane at a weighted average price of $0.25 per gallon, and 1.1 million Bbls of oil at a weighted average price of $54.75 per Bbl.

To the extent we have fixed the price of a portion of our estimated future production through 2022, we believe this hedge position provides some certainty to cash flows supporting our future operations and capital spending plans. As of December 31, 2016, the estimated fair value of our commodity derivative contracts was approximately $1.6 billion.

Credit Facilities

The current borrowing base under our revolving credit facility is $4.75 billion and lender commitments are $4.0 billion. The borrowing base under our revolving credit facility is redetermined semi-annually and is based on the estimated future cash flows from our proved oil and gas reserves and our commodity hedge positions. The next redetermination is scheduled to occur in April 2017. At December 31, 2016, we had $440 million of borrowings and $710 million of letters of credit outstanding under the revolving credit facility. Our revolving credit facility matures in May 2019. 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 our revolving credit facility.

Our consolidated subsidiary, Antero Midstream, has a revolving credit facility agreement that provides for lender commitments of $1.5 billion. At December 31, 2016, Antero Midstream had $210 million of borrowings outstanding under its revolving credit facility. The facility will mature in November 2019. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Midstream Credit Facility” for a description of this revolving credit facility.

Sale of Antero Midstream Units by Antero

On March 30, 2016, we sold 8,000,000 common units representing limited partner interests in Antero Midstream. We received net proceeds from the transaction of $178 million. The proceeds from the offering were used to pay down amounts outstanding under our revolving credit facility and to fund a portion of our 2016 development program.

Leasehold Acquisition and Related Issuance of Common Stock by Antero

On June 9, 2016, we entered into an agreement pursuant to which we acquired approximately 46,000 net acres of Marcellus Shale leasehold located primarily in Wetzel, Tyler, and Doddridge Counties in West Virginia, including approximately 14 MMcfe per day of net production, for a purchase price of approximately $505 million, which is subject to contractual purchase price adjustments for ongoing title work on the acquired acreage.

To finance the acquisition, on June 15, 2016 we issued 26,750,000 shares of our common stock and realized proceeds from the sale of approximately $753 million, net of offering expenses. We also granted the underwriters a 30-day option to purchase an additional 4,012,500 common shares. On July 12, 2016 the underwriters partially exercised the option and purchased an additional 3,012,500 shares, resulting in additional net proceeds from the offering of approximately $85 million. In addition to funding this acquisition, the offering proceeds were used for general corporate purposes including the reduction of amounts outstanding under our revolving credit facility in anticipation of future development of the purchased properties.

Private Placement of Common Stock by Antero

On October 7, 2016, we issued 6,730,769 shares of our common stock in a private placement, resulting in net proceeds of approximately $175 million. We used the proceeds to repay a portion of outstanding borrowings under our revolving credit facility and for general corporate purposes.

Issuance of 5.00% Senior Notes due 2025 by Antero

On December 21, 2016, we issued $600 million of 5.00% senior notes due March 1, 2025 at par. The proceeds from the issuance were used to retire the $525 million principal amount of our 6.00% senior notes due 2020 and for general corporate purposes.

As of December 31, 2016, Antero had four series of senior notes outstanding totaling $3.45 billion in aggregate principal amount. The notes bear interest at rates ranging from 5.00% to 5.625% and have maturity dates ranging from November 21, 2021 to March 1, 2025.

Issuance of 5.375% Notes due 2024 by Antero Midstream

On September 13, 2016, Antero Midstream issued $650 million of 5.375% senior notes due September 15, 2024 at par. The proceeds from the issuance were used by Antero Midstream to pay down amounts outstanding under its revolving credit facility. Antero Midstream has no other outstanding senior notes.

Formation of Joint Venture and Issuance of Common Units by Antero Midstream

On February 6, 2017, Antero Midstream formed a joint venture (the "Joint Venture") to develop processing assets in Appalachia with MarkWest Energy Partners, L.P. ("MarkWest"), a wholly owned subsidiary of MPLX, L.P. Antero Midstream and MarkWest will each own a 50% interest in the Joint Venture and MarkWest will operate the Joint Venture assets. The Joint Venture assets will consist of processing plants in West Virginia and a one-third interest in a recently commissioned MarkWest fractionator in Ohio.

In conjunction with the formation of the Joint Venture, on February 10, 2017 Antero Midstream issued 6,900,000 common units, including the underwriters' purchase option, generating net proceeds of approximately $223 million. Antero Midstream used the net proceeds to fund the initial $155 million contribution to the Joint Venture, repay outstanding borrowings under its credit facility, and for general partnership purposes.

Antero Midstream Equity Distribution Agreement

During the third quarter of 2016, Antero Midstream entered into an Equity Distribution Agreement (the "Distribution Agreement"). Pursuant to the terms of the agreement, Antero Midstream may sell, from time to time through brokers acting as its sales agents, common units representing limited partner interests having an aggregate offering price of up to $250 million. Sales of the common units are made by means of ordinary brokers' transactions on the New York Stock Exchange, at market prices, in block transactions, or as otherwise agreed to between Antero Midstream and the sales agents. Proceeds are used for general partnership purposes, which may include repayment of indebtedness and funding working capital or capital expenditures. The Partnership is under no obligation to offer and sell common units under the Distribution Agreement.

During the year ended December 31, 2016, Antero Midstream issued and sold 2,391,595 common units under the Distribution Agreement, resulting in net proceeds of $65.4 million after deducting commissions and other offering expenses. As of December 31, 2016, Antero Midstream had the capacity to issue additional common units under the Distribution Agreement up to an aggregate amount of $183.8 million.

Our Properties and Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared in accordance with the rules and regulations of the SEC.

Reserves Presentation

The following table summarizes our estimated proved reserves, related standardized measure, and PV-10 at December 31, 2014, 2015 and 2016. 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, 2016 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 32 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, 2014 were prepared assuming ethane rejection. Reserves at December 31, 2015 and 2016 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,		
	2014	2015	2016
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	3,285	3,627	4,426
Ethane (MMBbl)	—	247	250
C3+ NGLs (MMBbl)	80	113	151
Oil (MMBbl).	6	8	13
Total equivalent proved developed reserves (Bcfe)	3,803	5,838	6,914
Proved undeveloped reserves:			
Natural gas (Bcf)	7,250	5,906	4,988
Ethane (MMBbl)	—	—	304
C3+ NGLs (MMBbl)	250	227	252
Oil (MMBbl).	22	18	25
Total equivalent proved undeveloped reserves (Bcfe)	8,880	7,377	8,472
Total estimated proved reserves (Bcfe)	12,683	13,215	15,386
Proved developed producing (Bcfe)	3,508	5,553	6,587
Proved developed non-producing (Bcfe)	295	285	327
Percent developed	30 %	44 %	45 %
PV-10 (in millions)[1]	$ 11,320	$ 3,634	$ 3,676
Standardized measure (in millions)[1]	$ 7,635	$ 3,233	$ 3,287

[1] Pre-tax PV-10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. Pre-tax PV-10 is a non-GAAP financial measure. We believe that the presentation of pre-tax 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, pre-tax PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, pre-tax 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 pre-tax PV-10 amount is the discounted amount of estimated future income taxes. For more information about the calculation of standardized measure, see footnote 19 to our consolidated financial statements included in Item 8 of this Annual Report on Form 10-K.

The following sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), 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, 2014, 2015, and 2016:

	At December 31,		
(In millions, except per Mcf data)	**2014(1)**	**2015(2)**	**2016(3)**
Future net cash flows	$ 33,698	$ 12,569	$ 11,623
Present value of future net cash flows:			
Before income tax (PV-10)	$ 11,320	$ 3,634	$ 3,676
Income taxes	$ (3,685)	$ (401)	$ (389)
After income tax (Standardization measure)	$ 7,635	$ 3,233	$ 3,287

(1) 12-month average prices used at December 31, 2014 were $4.07 per MMBtu for natural gas, $45.89 per Bbl for NGLs, and $81.48 per Bbl for oil for the Appalachian Basin based on a $94.42 WTI reference price.

(2) 12-month average prices used at December 31, 2015 were $2.56 per MMBtu for natural gas, $14.19 per Bbl for NGLs, and $40.06 per Bbl for oil for the Appalachian Basin based on a $50.13 WTI reference price.

(3) 12-month average prices used at December 31, 2016 were $2.31 per MMBtu for natural gas, $13.58 per Bbl for NGLs, and $32.63 per Bbl for oil for the Appalachian Basin based on a $42.68 WTI reference price.

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 2014, 2015 and 2016 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 2016

The following table summarizes the changes in our estimated proved reserves during 2016 (in Bcfe):

Proved reserves, December 31, 2015	13,215
Extensions, discoveries, and other additions	2,637
Purchase of reserves	624
Increase in ethane recovery	1,359
Performance revisions	762
Revisions due to 5-year development rule	(2,478)
Price revisions	(47)
Sales of reserves in place	(10)
Production	(676)
Proved reserves, December 31, 2016	15,386

Extensions, discoveries, and other additions of 2,637 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales, which was aided in 2016 by longer laterals than in previous years and the utilization of advanced completion techniques. Purchases of 624 Bcfe relate to the acquisition of developed and undeveloped leasehold acreage in both the Marcellus and Utica Shales. Positive revisions of 1,359 Bcfe are due to an increase in our actual and assumed future ethane recovery based on existing sales contracts for ethane. Positive performance revisions of 762 Bcfe primarily relate to improved well performance. Negative revisions of 2,478 Bcfe were due to the impact of the SEC 5-year development rule. Due to the SEC 5-year development rule, these primarily dry gas reserves were displaced by our current development plan targeting more liquids-rich areas in our portfolio which have better economic returns. Negative revisions of 47 Bcfe were due to decreases in prices for natural gas, NGLs, and oil. Sales of 10 Bcfe was related to our sale of producing and non-producing leasehold in Pennsylvania. Our estimated proved reserves as of December 31, 2016 totaled approximately 15.4 Tcfe and increased by 16% over 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 2016 (in Bcfe):

Proved undeveloped reserves, December 31, 2015	7,377
Extension, discoveries, and other additions	2,111
Purchase of reserves	572
Increase in ethane recovery	1,344
Reclassifications to proved developed reserves	(1,208)
Performance revisions	776
Revisions due to 5-year development rule	(2,478)
Price revisions	(22)
Proved undeveloped reserves, December 31, 2016	8,472

Extensions, discoveries, and other additions during 2016 of 2,111 Bcfe of proved undeveloped reserves resulted from delineation and developmental drilling in the Marcellus and Utica Shales. Purchases of 572 Bcfe relate to the acquisition of undeveloped leasehold acreage in both the Marcellus and Utica Shales. Positive revisions of 1,344 Bcfe are due to an increase in our actual and assumed future ethane recovery based on existing sales contracts for ethane. Development drilling resulted in the reclassification of 1,208 Bcfe to proved developed reserves. Positive performance revisions of 776 Bcfe primarily relate to improved well performance. Negative revisions of 2,478 Bcfe were due to the SEC 5-year development rule. Due to the SEC 5-year development rule, these primarily dry gas reserves were displaced by our current development plan targeting more liquids-rich areas in our portfolio which have better economic returns. Negative revisions of 22 Bcfe were due to decreases in the prices for natural gas, NGLs, and oil. Wells that are not drilled within five years from booking are reclassified from proved reserves to probable reserves.

During the year ended December 31, 2016, we converted approximately 1,208 Bcfe of proved undeveloped reserves to proved developed reserves at a total capital cost of approximately $580 million, or $0.48 per Mcfe. We spent an additional $421 million on development costs related primarily to drilled and uncompleted wells and properties in the proved undeveloped classification at December 31, 2015, resulting in total development spending of $1.0 billion, as disclosed in note 19 to the consolidated financial statements included elsewhere in this report. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2016 are approximately $3.8 billion, or $0.45 per Mcfe, over the next five years. We believe that cash flows from operations and borrowings under our revolving credit facility will be sufficient to finance such future development costs and, to the extent that these amounts are insufficient to finance our growing development activities, we believe we will have sufficient access to the debt and equity capital markets and other sources of capital financing, as necessary. 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."

In the past four years, we have increasingly focused our land additions on liquids-rich areas where well economics provide higher returns based on the relative prices of NGLs and oil to dry gas. As a result of these efforts, we have built a large inventory of undrilled Marcellus and Utica Shale locations, including 3,630 locations classified as proved undeveloped, probable, or possible as of December 31, 2016.

We maintain a 5-year drilling plan that supports our corporate production growth target. The drilling schedule is reviewed periodically to ensure capital is allocated to the wells that have the highest rates of return within our inventory of undrilled well locations. As our acreage position has grown and well economics have changed, we have reallocated 5-year capital to areas with expected highest rates of return. This resulted in the reclassification of 2,478 Bcfe of reserves from proved undeveloped to probable during the year ended December 31, 2016 due to the 5-year development rule. Based on our then-current acreage position, 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. There has been no change in our view of reasonable certainty of the economic feasibility of these wells.

At December 31, 2016, our proved undeveloped locations that were scheduled for drilling over the next five years encompassed 77,000 acres. An estimated 14,300 of these acres, containing 301 wells associated with proved undeveloped reserves, are subject to renewal prior to scheduled drilling. Some of these leases have contract renewal options and some will need to be renegotiated. We estimate a potential cost of $50 million to $65 million to renew the 14,300 acres based upon current leasing authorizations and option to extend payments. Proved undeveloped reserves of 999 Bcfe are related to these leases. Historically, we have had a high success rate in renewing Appalachian 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 be unable to renew leases covering approximately 100 Bcfe of these proved undeveloped reserves.

If we are unable to renew these leases prior to the scheduled drilling dates, it will reduce our quantities of proved undeveloped reserves.

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2014, 2015, and 2016 included in this Annual Report on Form 10-K were prepared by our internal reserve engineers in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. The technical persons responsible for overseeing the audit of our reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserve auditing process. Periodically, our technical team meets with the independent reserve engineers to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Our internally prepared reserve estimates and related reports are reviewed and approved by our Senior Vice President of Reserves, Planning & Midstream, Ward D. McNeilly. Mr. McNeilly has been with the Company since October 2010. Mr. McNeilly has 37 years of experience in oil and gas operations, reservoir management, and strategic planning. From 2007 to October 2010, Mr. McNeilly was the Operations Manager for BHP Billiton's Gulf of Mexico operations. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. From 1979 through 1996, Mr. McNeilly served in various domestic and international operations and reservoir and asset management positions with Amoco. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

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

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

Methodology Used to Apply Reserve Definitions

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

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 statistical 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 statistical proven area in the Utica Shale and (ii) each proved developed producing well in the Utica Shale only generates four direct offset well locations in the Utica Shale due to less relative maturity.

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, 2016. We prepare internal estimates of probable and possible reserves but have not included disclosure of such reserves in this report.

Production, Revenues, and Price History

Because natural gas, NGLs, and oil are commodities, the price that we receive for our production is 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 can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. The significant commodity price declines in late 2014 through 2015 and into 2016 are the most recent example of such volatility. A substantial or extended decline in gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of reserves that may be economically produced, and our ability to access capital markets. See "Item 1A. Risk Factors—Natural gas, NGLs, and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

Operations Data

The following table sets forth information regarding our production, realized prices, and production costs for the years ended December 31, 2014, 2015 and 2016. 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,		
	2014	2015	2016
Production data:			
Natural gas (Bcf)	317	439	505
C2 Ethane (MBbl)	—	201	6,396
C3+ NGLs (MBbl)	7,102	15,350	20,279
Oil (MBbl)	1,311	2,078	1,873
Combined (Bcfe)	368	545	676
Daily combined production (MMcfe/d)	1,007	1,493	1,847
Average prices before effects of derivative settlements:			
Natural gas (per Mcf)	$ 4.10	$ 2.37	$ 2.50
C2 Ethane (per Bbl)	$ —	$ 6.17	$ 8.28
C3+ NGLs (per Bbl)	$ 46.23	$ 17.15	$ 18.74
Oil (per Bbl)	$ 81.65	$ 34.05	$ 32.73
Combined average sales prices before effects of derivative settlements (per Mcfe)[(1)]	$ 4.73	$ 2.52	$ 2.60
Combined average sales prices after effects of derivative settlements (per Mcfe)[(1)]	$ 5.10	$ 4.10	$ 4.08
Average Costs (per Mcfe):			
Lease operating	$ 0.08	$ 0.07	$ 0.07
Gathering, compression, processing, and transportation	$ 1.26	$ 1.21	$ 1.31
Production and ad valorem taxes	$ 0.24	$ 0.14	$ 0.10
Marketing, net	$ 0.14	$ 0.23	$ 0.16
Depletion, depreciation, amortization, and accretion	$ 1.30	$ 1.31	$ 1.20
General and administrative (before equity-based compensation)	$ 0.28	$ 0.25	$ 0.20

(1) Average prices shown reflect both the before and after effects of our commodity hedging transactions. Our calculation of such effects includes gains or losses recognized on settlement of commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges for accounting purposes.

Productive Wells

As of December 31, 2016, we had a total of 778 gross (736 net) producing wells, averaging a 95% working interest, in the Marcellus Shale. This well count includes 527 gross (519 net) horizontal wells, 9 gross (0.07 net) non-operated wells in which we hold minor working interests, and 242 gross (217 net) vertical wells. In the Utica Shale, we had 168 gross (139 net) producing wells, averaging an 83% working interest, in the Utica Shale. This well count includes 155 gross (139 net) horizontal wells, and 13 gross (0.04 net) non-operated wells in which we hold minor working interests.

Additionally, at December 31, 2016 we had 16 net horizontal proved developed non-producing wells, and 140 gross horizontal wells (138 net) that were drilled and uncompleted or in the process of being completed. The non-operated wells and vertical wells in both the Marcellus and Utica Shales 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, 2016. A majority of our developed acreage is subject to liens securing our revolving credit facility. Approximately 55% of our net Marcellus acreage and 35% 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	83,960	82,559	446,294	381,560	530,254	464,119
Utica Shale	31,292	25,435	140,442	126,798	171,734	152,233
Total	115,252	107,994	586,736	508,358	701,988	616,352

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

	Marcellus	
County, State	**Gross Acres**	**Net Acres**
Doddridge, WV	146,226	140,900
Gilmer, WV	14,194	11,003
Harrison, WV	101,245	95,615
Lewis, WV	427	64
Marion, WV	7,444	5,242
Monongalia, WV	3,603	2,569
Pleasants, WV	6,800	4,206
Ritchie, WV	76,987	74,564
Tyler, WV	93,331	78,010
Wetzel, WV	69,237	43,030
Fayette, PA	7,251	5,407
Washington, PA	406	406
Westmoreland, PA	3,103	3,103
Total Marcellus Shale	530,254	464,119

	Ohio Utica	
	Gross Acres	**Net Acres**
Athens, OH	84	84
Belmont, OH	13,528	13,375
Guernsey, OH	4,512	3,567
Harrison, OH	577	577
Monroe, OH	64,288	61,301
Noble, OH	85,666	70,898
Washington, OH	3,079	2,431
Total Utica Shale	171,734	152,233
Total Marcellus and Utica Shale	701,988	616,352

Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of December 31, 2016 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. The Company is either planning to drill or is actively pursuing lease extensions or renewals on the majority of this acreage.

	Marcellus		Ohio Utica		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
2017	46,976	36,203	43,773	34,467	90,749	70,670
2018	40,409	30,626	28,973	23,230	69,382	53,856
2019	59,427	49,745	35,473	31,420	94,900	81,165

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2014, 2015, and 2016. Gross wells reflect the sum of all wells in which we own an interest and includes historical drilling activity in the Appalachian Basin. Net wells reflect the sum of our working interests in gross wells.

	Year ended December 31,					
	2014		2015		2016	
	Gross	Net	Gross	Net	Gross	Net
Marcellus						
Development wells:						
Productive	77	76	69	68	72	71
Dry	—	—	—	—	—	—
Total development wells	77	76	69	68	72	71
Exploratory wells:						
Productive	43	42	5	5	16	16
Dry	—	—	—	—	—	—
Total exploratory wells	43	42	5	5	16	16
Utica						
Development wells:						
Productive	11	10	21	18	35	35
Dry	—	—	—	—	—	—
Total development wells	11	10	21	18	35	35
Exploratory wells:						
Productive	23	19	37	33	5	5
Dry	—	—	—	—	—	—
Total exploratory wells	23	19	37	33	5	5
Total						
Development wells:						
Productive	88	86	90	86	107	106
Dry	—	—	—	—	—	—
Total development wells	88	86	90	86	107	106
Exploratory wells:						
Productive	66	61	42	38	21	21
Dry	—	—	—	—	—	—
Total exploratory wells	66	61	42	38	21	21

The figures in the table above do not include 140 gross wells (138 net) that were drilled and uncompleted or in the process of being completed at December 31, 2016.

Delivery Commitments

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

As of December 31, 2016, our firm sales commitments through 2021 included:

Year Ending December 31,	Volume of Natural Gas (MMBtu/d)	Firm Transport Capacity Utilized (MMBtu/d)	Volume of Ethane (Bbl/day)
2017	936,000	820,000	27,500
2018	1,030,000	910,000	29,500
2019	1,050,000	940,000	29,500
2020	930,000	890,000	29,500
2021	850,000	810,000	29,500

In addition to the commitments listed in the table above, we have firm sales commitments for 100% of our C4+ NGL production from April 2017 through March 2018, and 100% of our oil and condensate production from February 2017 through March 2018.

As provided in the table above, we utilize a part of our firm transportation capacity to deliver gas and NGLs under the majority of these firm sales contracts. We have firm transportation contracts that require us to either ship products on said pipelines or pay demand charges for shortfalls. The minimum demand fees are reflected in our table of contractual obligations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations." If our production quantities are insufficient to meet such commitments, we may purchase third party products or market our excess firm transportation capacity to third parties.

Gathering and Compression

Our exploration and development activities are supported by the natural gas gathering and compression assets of our subsidiary, Antero Midstream, as well as by third-party gathering and compression arrangements. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production. Our relationship with Antero Midstream allows us to obtain the necessary gathering and compression capacity for our production and we have leveraged our relationship with Antero Midstream to support our growth. For the years ended December 31, 2015 and 2016, Antero Midstream spent approximately $320 million and $228 million, respectively, on gas and condensate gathering and compression infrastructure that services our production. Subject to any pre-existing dedications or other third-party commitments, we have dedicated to Antero Midstream all of our current and future acreage in West Virginia, Ohio, and Pennsylvania for gathering and compression services.

As of December 31, 2016, Antero Midstream, owned and operated 213 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 Crestwood, Energy Transfer Partners L.P., and Summit Midstream. As of December 31, 2016, Antero Midstream owned and operated 10 compressor stations and we utilized 15 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, 2016, Antero Midstream owned and operated 113 miles of low-pressure, high-pressure, and condensate pipelines in the Utica Shale, and Antero owned and operated 8 miles of high-pressure pipelines. As of December 31, 2016, Antero Midstream owned and operated one compressor station and we utilized five 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. Natural gas containing significant amounts of NGLs 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 have their 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 separated out 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 will 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 NGL 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. In late 2015, we began recovering some ethane as the first de-ethanizer was placed on line at the Sherwood gas processing facility. Our first international ethane sales contract is expected to commence in late 2017.

We have contracted with MarkWest Energy Partners L.P. to provide cryogenic processing capacity for our Marcellus and Utica Shale production as follows:

	Plant Processing Capacity (MMcf/d)	Antero Contracted Firm Processing Capacity (MMcf/d)	Anticipated Date of Completion
Marcellus Shale:			
Sherwood 1	200	200	In service
Sherwood 2	200	200	In service
Sherwood 3	200	150	In service
Sherwood 4	200	200	In service
Sherwood 5	200	200	In service
Sherwood 6	200	200	In service
Sherwood 7	200	200	1Q 2017
Sherwood 8	200	200	3Q 2017
Sherwood 9	200	200	1Q 2018
Sherwood 10	200	200	3Q 2018
Marcellus Shale Total	2,000	1,950	
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	

Through our investment in the Joint Venture, we acquired a 50% non-operated equity interest in certain of the existing and future Sherwood gas processing plants. The Joint Venture also owns a 33 1/3% interest in a fractionation facility located at the Hopedale complex in Harrison County, Ohio. The Joint Venture’s processing activity will begin with the seventh plant at the Sherwood facility. The Joint Venture will provide processing services to Antero Resources 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 2034.
- 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"), ANR Pipeline ("ANR-Gulf"), Equitrans pipeline ("EQT"), and the M3 Appalachian Gathering System ("M3"). 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 571,000 MMBtu per day. Of the 571,000 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 2017 through 2025.
    - We have a firm transportation contract with Stonewall Gas Gathering for 1,090,000 MMBtu per day which will transport 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 volumes that increase from the interim capacity of 355,000 MMBtu per day to 790,000 MMBtu per day in June 2018. 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 beginning in June 2018. These contracts expire at various dates from 2030 through 2037.
    - We have a firm transportation contract for 590,000 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 increases to 790,000 MMBtu per day in June 2018. This contract expires in 2030.
    - We have a firm transportation contract for 600,000 MMBtu per day on ANR-Gulf to deliver natural gas from Ohio to the Gulf Coast market. This contract expires in 2045.
    - We have a firm transportation contract for 800,000 MMBtu per day, estimated to be in-service in mid 2017, on the Energy Transfer Rover Pipeline which will connect the Marcellus and Utica Shale assets to Midwest and Gulf Coast markets via our existing firm transportation on ANR Chicago and ANR Gulf. This contract expires in 2033.
    - We have firm transportation contracts for 250,000 MMBtu per day on EQT to deliver Marcellus natural gas to Tetco M2 and other various delivery points. The contracts expire at various dates from 2021 through 2025.
    - We have firm transportation contracts for 375,000 MMBtu per day on the M3 Appalachian Gathering System to deliver Marcellus natural gas to TETCO M2 and other various local delivery points. These contracts expire in 2023.
- 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. 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. Mariner East 2 is expected to be in-service in the fourth quarter of 2017. 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 2017 annual production levels, we estimate that we could incur total annual net marketing costs of $60 million to $105 million in 2017 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third party gas and capture positive basis differentials. Where permitted, we continue to actively market any excess capacity in order to offset minimum commitment fees.

Water Handling and Treatment Operations

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

Antero Midstream owns two independent fresh water distribution systems that distribute fresh water from the Ohio River and several regional water sources for well completion operations in the 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, 2016, Antero Midstream had the ability to store 5.0 million barrels of fresh water in 36 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 has provided water delivery services to neighboring oil and gas producers within and adjacent to our operating area, and is able to provide water delivery services to other oil and gas producers in the area, subject to commercial arrangements, in an effort to reduce water truck traffic.

As of December 31, 2016, Antero Midstream owned and operated 116 miles of buried fresh water pipelines and 87 miles of movable surface fresh water pipelines in the Marcellus Shale, as well as 23 fresh water storage facilities equipped with transfer pumps. As of December 31, 2016, Antero Midstream owned and operated 49 miles of buried fresh water pipelines and 34 miles of movable surface fresh water pipelines in the Utica Shale, as well as 13 fresh water storage facilities equipped with transfer pumps.

In August 2015, we committed to developing an advanced waste water treatment complex in Doddridge County, West Virginia. The complex was transferred to Antero Midstream in conjunction with the sale of our water handling systems in September 2015. The waste water treatment complex, once completed, will include a 60,000 barrel per day facility that will allow Antero Midstream to treat our flowback and produced water for subsequent use or sale for well completions. The treatment facility is expected to be in service in the fourth quarter of 2017. Late in 2015, Antero Midstream began providing us with waste water services for our well completion operations, including waste water transportation, disposal, and treatment.

Major Customers

For the year ended December 31, 2016, two of our customers accounted for approximately 29% and 13% of our total product revenues, respectively. For the year ended December 31, 2015, three of our customers accounted for 19%, 18%, and 13% of our total product revenues, respectively. For the year ended December 31, 2014, three of our customers accounted for 29%, 16%, and 12% of our total product revenues, respectively. Although a substantial portion of our production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as we believe other customers or markets would be accessible to us.

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 summer. This can also reduce seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

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

Regulation of the Oil and Natural Gas Industry

General

Our oil and natural gas operations are subject to extensive, and frequently changing, laws and regulations related to well permitting, drilling, and completion, and to the production, transportation and sale of oil, natural gas and NGLs. 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 industries 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 three U.S. states, 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 oil, natural gas, and NGLs 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 for 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 service, which occurs upstream of jurisdictional transmission services, is 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 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 does 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.

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

The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1,000,000 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

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 a permit 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 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 capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

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

The Resource Conservation and Recovery Act, or RCRA, and analogous state laws, establish detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the U.S. Environmental Protection Agency, or the EPA, or state agencies under RCRA's less stringent nonhazardous solid waste provisions, or under state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as waste solvents, laboratory wastes and waste compressor oils that may become regulated as hazardous wastes if such wastes have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site 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, new EPA and U.S. Army Corps of Engineers rules defining the scope of the EPA's and the Corps' jurisdiction became effective. To the extent the rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. The process for obtaining permits has the potential to delay the development of 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 waste water 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 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. 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. More recently, 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, or NESHAP, 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. 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 on a case-by-case basis. 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 that establish emission standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. The EPA's rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rule package extends existing VOC standards under the EPA's Subpart OOOO of the NSPS, or NSPS Quad O, to include previously unregulated equipment within the oil and natural gas source category. In addition, in January 2016, Pennsylvania announced new rules that will require the Pennsylvania Department of Environmental Protection, or PADEP, to develop a new general permit for oil and gas exploration, development, and production facilities and liquids loading activities, requiring best available technology for equipment and processes, enhanced record-keeping, and quarterly monitoring inspections for the control of methane emissions. The PADEP also intends to issue similar methane rules for existing sources. In addition, the department has also proposed to establish Best Management Practices, including leak detection and repair ("LDAR") programs, to reduce fugitive methane emissions from production, gathering, processing, and transmission facilities. These rules have the potential to increase our compliance costs.

We have been making efforts to reduce methane emissions since March 2005, when we engaged local community groups in Colorado regarding our activities in the Piceance Basin in discussions on how to minimize impacts from our operations. As noted above, in 2012, the EPA promulgated NSPS Quad O, which, among other actions, requires the use of reduced emission completions, or "green completions," to control emissions of VOCs from hydraulically fractured natural gas wells. Green completions have the added benefit of reducing methane emissions from our operations. The green completions requirements of NSPS Quad O became effective in January 2015, but we have been performing green completions since before the EPA's rules became effective. We were one of the first operators to implement green completions in Colorado back 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 believe we have a long history of managing methane emissions from our operations, as demonstrated by our longstanding use of green completions.

When we permit a facility, we are required to install pollution control equipment at the wellsite in accordance with the requirements of the NSPS for New Stationary Sources. At wellpads, this consists of installing combustors with a control efficiency of 98% to control tank methane and VOC emissions. In addition to combustors, we also install Vapor Recovery Units, or VRUs, in order to capture methane and VOC emissions and direct them down the sales line, rather than flaring those emissions. Per applicable regulations, we also install low-bleed pneumatic controls at wellpads, which serve to reduce methane emissions. We may also install Vapor Recovery Towers, or VRTs, to further reduce methane and VOC flashing emissions from storage tanks when we have more than a nominal amount of oil production in order to produce sufficient gas to allow safe and proper running of the VRTs. At compressor stations, through the use of non-selective catalytic reduction, we reduce methane and VOC emissions from engines by at least 70%. Compressor Station tank and dehydration units are typically controlled by combustors or VRUs. We control our methane and VOC emissions consistent with available emission control technology as required by law and as applicable to our operations.

Our methane and VOC control program consists of installing the emission controls described above, performing inspections, and conducting preventative maintenance and repairs to minimize emissions leakage. For example, we have implemented an LDAR program for our well pad and compressor station operations. During 2015, we added two fulltime staff members to manage the LDAR program. LDAR program inspections utilize a state of the art Forward Looking Infrared Radar (FLIR) camera to identify equipment leaks. Our Operations group has a maintenance program in place, which includes cleaning, greasing and replacing thief hatch seals, and other measures as required to further minimize the potential for leaks, In 2015, we implemented new thief hatch designs with improved seals for our tanks. While the LDAR program is not mandatory in all areas of our operations, we have implemented it uniformly across all of our activities. We believe that our efforts to date have resulted in a declining volume of methane emissions based on the decreasing number of leaks detected as part of our LDAR program. In addition, since 2011 and in accordance with EPA regulations, we have monitored or calculated our GHG emissions, including emissions of methane, and reported them to the EPA on an annual basis. Our current report of GHG emissions from covered operations during 2016 will be submitted to the EPA by March 31, 2017. Overall, through the use of Green Completions we have seen significant decreases in GHG emissions from our operations. Furthermore, we believe that our efforts to comply with the 2012 NSPS Quad O have resulted in us being well positioned to comply with the EPA's recently finalized NSPS Quad Oa regulations to reduce methane and VOC emissions from oil and natural gas operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, the prospect for adoption of significant legislation at the federal level to reduce GHG emissions is perceived to be low at this time. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could also adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Depending on the severity of any such limitations, the effect on the value of our reserves could be significant. Finally, it should be noted that a number of scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events; if any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations, as does most of the domestic oil and natural gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act, or the SDWA, over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding such activities. Also, in May 2014, the EPA proposed rules under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, no further action has been taken on the proposal. The EPA also proposed in April 2015 to prohibit the discharge of waste water from hydraulic fracturing operations to publicly owned waste water 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 waste water to surface waters; and disposal or storage of fracturing waste water in unlined pits. Since the report 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. Also, in June 2016, the EPA finalized rules that would establish new air emission controls for methane emissions from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission, and storage activities. The final rule 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, fugitive emissions from well sites and compressors, equipment leaks at natural gas processing plants, and pneumatic pumps. The rules also extend existing requirements for the emission of volatile organic compounds to the same equipment and processes. In addition, the U.S. Department of the Interior published a final rule in March 2015 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule pending a final decision on whether it may be implemented. Other governmental agencies, including the U.S. Department of Energy have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, in January 2016, the PADEP issued new rules establishing stricter disposal requirements for wastes associated with hydraulic fracturing activities, which include, among other things, a prohibition on the use of centralized impoundments for the storage of drill cuttings and waste fluids. 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 sought 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 is required to make a determination as to whether more than 250 species classified as endangered or threatened should be listed under the ESA by no later than completion of the agency's 2017 fiscal year. For example, in April 2015, the USFWS listed the northern long-eared bat, whose habitat includes the areas in which we operate, as a threatened species under the ESA. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2016, nor do we anticipate that such expenditures will be material in 2017.

Employees

As of December 31, 2016, we had 528 full-time employees, including 36 in executive, finance, treasury, legal, and administration, 22 in information technology, 23 in geology, 230 in production and engineering, 93 in midstream, 79 in land, and 45 in accounting. 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 with the Securities and Exchange Commission (the "SEC") our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K. We make these documents available free of charge at *www.anteroresources.com* under the "Investors Relations" link as soon as reasonably practicable after they are filed or furnished with the SEC.

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

Item 1A. Risk Factors

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

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

The prices we receive for our natural gas, NGLs, and oil production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs, and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. This market 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 natural gas, 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;
- 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.

In late 2014, global energy commodity prices declined precipitously as a result of several factors, including an increase in worldwide commodity supplies, a stronger U.S. dollar, relatively mild weather in large portions of the U.S. during the 2014 and 2015 winter months, and strong competition among oil producing countries for market share. Depressed commodity prices continued into 2015 and 2016, although a modest recovery has occurred in late 2016 and early 2017.

Spot prices for WTI declined significantly since June 2014 levels of approximately $106.00 per Bbl and have ranged from less than $30.00 per Bbl in February 2016 to approximately $53.00 per Bbl in February 2017. Spot prices for Henry Hub natural gas also declined significantly from approximately $4.40 per MMBtu in January 2014 to $2.00 per MMBtu in March 2016. Natural gas prices have recently recovered to approximately $3.00 per MMBtu in February 2017 due to increases in demand as a result of colder winter weather in many regions of the United States. Spot prices for propane, which is the largest portion of our NGLs sales, declined from approximately $1.55 per gallon in January 2014 to less than $0.35 per gallon in January 2016. Prices for propane have recovered to over $0.70 per gallon in February 2017.

Lower commodity prices reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

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

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, and acquisition of oil and gas reserves. Our cash flow used in investing activities related to drilling, completions, and land expenditures, including acquisitions, was approximately $2.1 billion in 2016. Our board of directors has approved a capital budget for 2017 of $1.5 billion that includes $1.3 billion for drilling and completion and $200 million for core leasehold acreage additions and extension. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations and borrowings under our revolving credit facility or capital market transactions; 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 estimates 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 further reduction in commodity prices from current levels may result in an additional decrease in our actual capital expenditures, which would negatively impact our ability to grow production. For additional discussion of the risks regarding our ability to obtain funding, please read "Item 1A. Risk Factors – The borrowing base under our revolving credit facility is subject to semi-annual redetermination by our lenders, which could result in a reduction of our borrowing base. This may hinder or prevent us from meeting our future capital needs." The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

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

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our revolving credit facility, including any potential decrease in the borrowing base.

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

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 natural gas production. 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 often uncertain before drilling commences.

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

- further or prolonged declines in oil, NGLs, and natural gas prices;
- limitations in the market for oil, NGLs, and natural gas;

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

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

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

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

The borrowing base under our revolving credit facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs.

The borrowing base under our revolving credit facility is currently $4.75 billion, and lender commitments under our revolving credit facility are $4.0 billion. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is expected to occur in April 2017. Our borrowing base may decrease as a result of a further decline in oil or natural gas 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 current or further declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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

Due to the decline in commodity prices throughout 2015 and 2016, the financial markets have exerted downward pressure on stock prices and credit capacity for companies throughout the energy industry. In particular, throughout much of 2015 and 2016, the market for senior unsecured notes was unfavorable for high-yield issuers such as us. Our plans for growth require regular access to the capital and credit markets, including the ability to issue senior unsecured notes. Although the market for high-yield debt securities improved in the latter part of 2016, 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.

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, 2016, 55% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 8.5 Tcfe of estimated proved undeveloped reserves will require an estimated $3.8 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.

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

We have various firm transportation, gas processing, gathering and compression service and water handling and treatment agreements in place, each with minimum volume delivery commitments. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to utilize our full firm transportation and processing capacity. Our firm transportation agreements expire at various dates from 2018 to 2058, our gas processing, gathering, and compression services agreements expire at various dates from 2017 to 2029, and our water services agreement with Antero Midstream expires in 2035. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. As of December 31, 2016, our long-term contractual obligations under agreements with minimum volume commitments totaled over $17.8 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 2017 annual production levels, we estimate that we could incur total annual net marketing costs of $60 million to $105 million in 2017 for unutilized transportation capacity depending on the amount of unutilized capacity that can be marketed to third parties or utilized to transport third party gas and capture positive basis differentials. Additionally, in years subsequent to 2017, our commitments and obligations under firm transportation agreements continue to increase and our net marketing expense could continue to 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.

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

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

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

The hydraulic fracture stimulation process on which we depend to produce commercial quantities of oil and gas requires the use and disposal of significant quantities of water. The availability of disposal alternatives to receive all of the water produced from our wells may affect our production. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, 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. Also, in May 2014, the EPA proposed rules under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, no further action has been taken on the proposal. The EPA also proposed in April 2015 to prohibit the discharge of waste water from hydraulic fracturing operations to publicly owned waste water 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 waste water to surface waters; and disposal or storage of fracturing waste water in unlined pits. Since the report 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. Also, in June 2016, the EPA finalized rules that would establish new air emission controls for methane emissions from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission, and storage activities. The final rule 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, fugitive emissions from well sites and compressors, equipment leaks at natural gas processing plants, and pneumatic pumps. The rules also extend existing requirements for the emission of volatile organic compounds to the same equipment and processes. In addition, the U.S. Department of the Interior published a final rule in March 2015 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision is pending, however. Other governmental agencies, including the U.S. Department of Energy have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, in January 2016, the PADEP issued new rules establishing stricter disposal requirements for wastes associated with hydraulic fracturing activities, which include, among other things, a prohibition on the use of centralized impoundments for the storage of drill cuttings and waste fluids. 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 sought 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.

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

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

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

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

Our revolving credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi-annual basis based upon projected revenues from the natural gas properties and commodity derivatives securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. For additional discussion of the risks regarding our ability to obtain funding under our revolving credit facility, please read "Item 1A. Risk Factors – A sustained decline of oil and natural gas prices may affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our revolving credit facility. This may hinder or prevent us from meeting our future capital needs."

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

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, during 2016, we had estimated average outstanding borrowings under our revolving credit facilities of approximately $1.1 billion, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased interest expense for that period of approximately $11 million and a corresponding decrease in our net income before the effects of income taxes. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and natural gas prices do not improve, our cash flows may be adversely impacted. Additionally, if development drilling costs increase significantly in the future, our hedged revenues may not be sufficient to cover our costs.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2016, we had entered into a number of hedge contracts for approximately 3.4 Tcfe of our projected natural gas, NGLs, and oil production through December 31, 2022. We are currently realizing a significant benefit from these hedge positions. For example, for the years ended December 31, 2015 and 2016, we received approximately $857 million and $1.0 billion, respectively, in revenues from cash settled derivatives pursuant to our hedging arrangements. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2015 and 2016 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 price at which we have been able to hedge future production has decreased as a result. The sustained weakness in commodity prices in 2016 and through the first quarter of 2017 has adversely affected our ability to hedge future production, particularly on a local basis. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, 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 a significant part of our overall future revenues. For example, for the years ended December 31, 2015 and 2016, approximately 88% and 97%, respectively, of our production was protected from price declines by our financial derivative contracts. 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 derivative activities could result in financial losses or could reduce our earnings. In certain circumstances, we may have to make cash payments under our hedging arrangements and these payments could be significant.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, NGLs, and oil we enter into derivative instrument contracts for a significant portion of our natural gas production, including fixed-price swaps. As of December 31, 2016, we had entered into hedging contracts through December 31, 2022 covering a total of approximately 3.4 Tcfe of our projected natural gas, NGLs, and oil production at an average index price of $3.63 per MMBtu. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

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

- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil 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 or oil prices upon settlement of our derivative contracts exceed the price at which we have hedged our commodities, we will be obligated to make cash payments to our hedge counterparties, which could, in certain circumstances, be significant.

Our hedging transactions expose us to counterparty credit risk.

As of December 31, 2016, the estimated fair value of our commodity derivative contracts was approximately $1.6 billion at December 31, 2016 includes the following receivables by bank counterparty: Morgan Stanley—$551 million; Barclays—$392 million; JP Morgan—$306 million; Wells Fargo—$159 million; Scotiabank—$136 million; Canadian Imperial Bank of Commerce—$58 million; Toronto Dominion Bank—$32 million; Fifth Third Bank—$12 million; Bank of Montreal—$10 million; and Capital One—$2 million. The credit ratings of certain of these banks have been downgraded in recent years because of the sovereign debt crisis in Europe.

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.

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

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

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

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

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

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

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

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

As of December 31, 2016, we had 3,630 identified potential horizontal well locations located in our proved, probable, and possible reserve base. As a result of the limitations described above, we may be unable to drill many of our potential well locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified potential well locations, see "Item 1. Business and Properties—Our Properties and Operations—Estimated Proved Reserves—Identification of Potential Well Locations."

Approximately 82% 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 82% of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, approximately 45% and 65% of our natural gas leases related to our Marcellus and Utica acreage, respectively, require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage. For more information on our future potential acreage expirations, see "Item 1. Business and Properties—Our Properties and Operations—Acreage—Undeveloped Acreage Expirations."

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, 2016, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. Furthermore, substantially all of our liquids rich natural gas is processed at two processing facilities. If service interruptions are experienced at either facility, it would lead to a decline in our production and 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 results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

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

Accounting rules require that we periodically review the carrying value of our properties for possible impairment if the estimated future undiscounted cash flows are less than the carrying value of our properties. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. We may incur 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 production will decline, which would adversely affect our future cash flows and results of operations.

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

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

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

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

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through the sale of our oil and gas production ($224 million in receivables at December 31, 2016), which we market to energy marketing companies, end users, and refineries, the marketing of our excess firm transportation capacity ($38 million at December 31, 2016), and joint interest receivables ($15 million at December 31, 2016). Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. The largest purchaser of our natural gas during the twelve months ended December 31, 2016 purchased approximately 29% of our operated production. 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 worker health and 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 worker health and 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 Colorado, West Virginia, Ohio, and Pennsylvania in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. We are not yet able to estimate what our aggregate exposure for monetary or other damages resulting from these or other similar claims might be. 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 or results of operations.

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

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

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

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

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

We 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 processing agreement that we have entered into with Antero Midstream, we have dedicated the gathering and processing 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 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 processing 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 waste water 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.

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

Properties that we decide to drill that do not yield natural gas or oil in commercially viable quantities will adversely affect our results of operations and financial condition. 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 assure you 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;
- 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, 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, and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs, and oil pipelines or gathering system capacity. In addition, if natural gas, NGLs, or oil quality specifications for the third-party natural gas, NGLs, or oil pipelines with which we connect change so as to restrict our ability to transport natural gas, NGLs, or oil, 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.

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

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

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

Changes to existing or new regulations may unfavorably impact us, could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. 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 or results of operations.

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

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. Although the FERC has not made any formal determinations with respect to any of our facilities, we believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress.

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

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

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

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources. 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 on a case by case basis. 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.

As noted above, in June 2016, the EPA finalized new regulations that establish emission standards for methane and volatile organic compounds from new and modified oil and natural gas production and natural gas processing and transmission facilities. The EPA's rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rule package extends existing VOC standards under the EPA's Subpart OOOO to include previously unregulated equipment within the oil and natural gas source category.

In addition, in January 2016, Pennsylvania announced new rules that will require the PADEP to develop a new general permit for oil and gas exploration, development, and production facilities and liquids loading activities, requiring best available technology for equipment and processes, enhanced record-keeping, and quarterly monitoring inspections for the control of methane emissions. The PADEP also intends to issue similar methane rules for existing sources. In addition, the department has also proposed to establish Best Management Practices, including leak detection and repair, or LDAR, programs, to reduce fugitive methane emissions from production, gathering, processing, and transmission facilities. These rules have the potential to increase our compliance costs.

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

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

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

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

Terrorist or cyber-attacks may significantly affect the energy industry, including our operations and those of our 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. 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.

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

Natural gas operations in our operating areas can be adversely affected by regulations designed to protect various wildlife. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in constraints on our exploration and production activities. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

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.

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and production may be eliminated as a result of future legislation. Additionally, state legislation may impose new or increased taxes or fees on natural gas and oil extraction.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but have not been limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower U.S. federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may also change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and production. The resulting increase in costs due to such changes could have an adverse effect on our financial position, results of operations and cash flows.

Certain states may also impose new or increased taxes or fees on natural gas and oil extraction. For example, Pennsylvania imposes an annual natural gas impact fee on natural gas and oil operators in Pennsylvania for each well drilled for a period of fifteen years. The fee is on a sliding scale set by the Public Utility Commission and is based on two factors: changes in the Consumer Price Index and the average NYMEX natural gas prices from the last day of each month. There can be no assurance that the impact fee will remain as currently structured or that new or additional taxes will not be imposed. Additionally, Ohio has previously considered, and its legislature continues to consider, proposals to increase the current severance tax imposed on natural gas or oil in Ohio. Pennsylvania does not currently impose a severance tax on natural gas or oil It is possible that each of these states could propose and implement a new or increased severance tax in the coming years, which would negatively affect our future cash flows and financial condition.

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

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

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

In March 2011, we received orders for compliance from federal regulatory agencies, including the U.S. Environmental Protection Agency relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non-compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. We have responded to all pending orders and are actively cooperating with the relevant agencies. We believe that these actions will result in monetary sanctions exceeding $100,000. We have begun settlement discussions with the relevant agencies to resolve the orders for compliance, but we are unable to estimate the total amount of monetary sanctions to resolve such orders or costs to remediate these locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date, and management does not expect these matters to have a material adverse effect on our financial condition, results of operations, or cash flows.

The Company is the plaintiff in two nearly identical lawsuits against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively “SJGC”) pending in United States District Court in Colorado. The Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC has short paid, and continues to short pay, the Company in connection with two long term gas contracts. Under those contracts, SJGC are long term purchasers of some of the Company’s natural gas production. Deliveries under the contracts began in October 2011 and the delivery obligation continues through October 2019. SJGC unilaterally breached the contracts claiming that the index prices specified in the contracts, and the index prices at which SJGC paid for deliveries from 2011 through September 2014, are no longer appropriate under the contracts because a market disruption event (as defined by the contract) has occurred and, as a result, a new index price is to be determined by the parties. Beginning in October 2014, SJGC began short paying the Company based on indexes unilaterally selected by SJGC and not the index specified in the contract. The Company contends that no market disruption event has occurred and that SJGC have breached the contracts by failing to pay the Company based on the express price terms of the contracts. Through December 31, 2016, the Company estimates that it is owed approximately $55 million more than SJGC has paid using the indexes unilaterally selected by them.

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively, “WGL”) are also involved in a pricing dispute involving contracts that the Company began delivering gas under in January 2016. The Company has invoiced WGL at the index price specified in the contract and WGL has paid the Company based on that invoice price; however, WGL asserted that the index price is no longer appropriate under the contracts and 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.

We are party to various other legal proceedings and claims in the ordinary course of our business. We believe 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 our consolidated financial condition, results of operations, or cash flows.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Common Stock

We have one class of common shares outstanding, our par value $0.01 per share common stock. Our common stock is traded on the New York Stock Exchange under the symbol "AR." On February 23, 2017, our common stock was held by 323 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the common stock on the New York Stock Exchange for each period presented.

	Common Stock	
	High	Low
2016:		
Quarter ended December 31, 2016	$ 28.30	$ 23.58
Quarter ended September 30, 2016	$ 28.24	$ 24.83
Quarter ended June 30, 2016	$ 30.66	$ 24.26
Quarter ended March 31, 2016	$ 27.85	$ 19.00
2015:		
Quarter ended December 31, 2015	$ 26.59	$ 18.50
Quarter ended September 30, 2015	$ 34.56	$ 20.00
Quarter ended June 30, 2015	$ 46.06	$ 33.89
Quarter ended March 31, 2015	$ 42.42	$ 33.25

Issuer Purchases of Equity Securities

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

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet be Purchased Under the Plan
October 1, 2016 - October 31, 2016	123,468	$ 26.51	—	N/A
November 1, 2016 - November 30, 2016	356,594	$ 25.38	—	N/A
December 1, 2016 - December 31, 2016	160,437	$ 25.42	—	N/A

Shares repurchased represent shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of restricted stock and restricted stock units held by our employees.

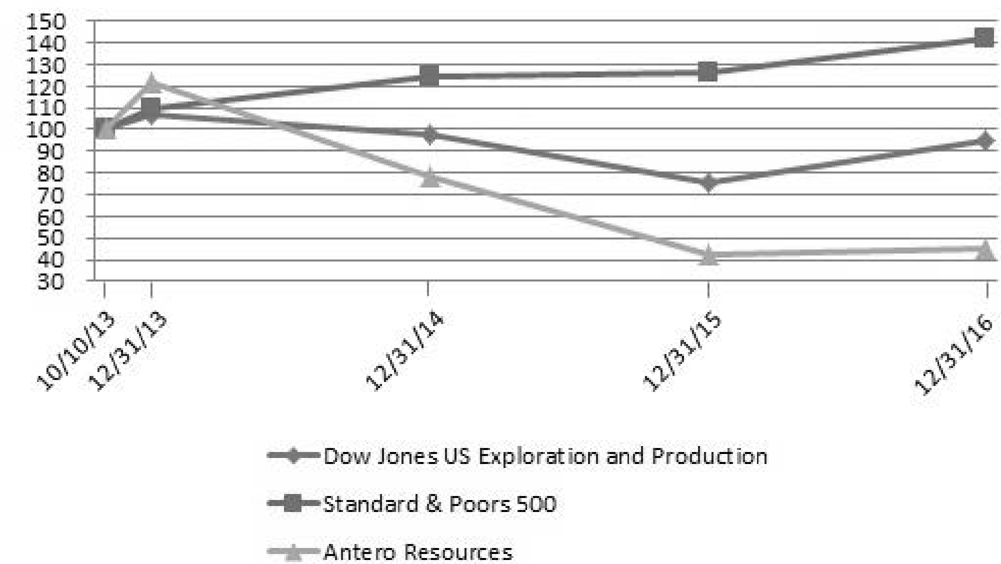
Dividend Restrictions

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

Stock Performance Graph

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

Comparison of Cumulative Total Returns Among Antero Resources Corporation, the S&P 500 Index, and the Dow Jones US Exploration and Production Index



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

Item 6. Selected Financial Data

The following table shows our selected historical consolidated financial data, for the periods ended and as of the dates indicated, for Antero Resources Corporation and its subsidiaries (including Antero Midstream Partners LP).

The selected statement of operations data and statement of cash flows data for the years ended December 31, 2014, 2015, and 2016 and the balance sheet data as of December 31, 2015 and 2016 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, 2012 and 2013 and the balance sheet data as of December 31, 2012, 2013, and 2014 are derived from our audited consolidated financial statements not included in Item 8 of this Annual Report on Form 10-K.

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

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

The statement of cash flows data for the years ended December 31, 2014 and 2015 has been recast to present the effects of the adoption of ASU No. 2016-09, *Stock Compensation–Improvements to Employee Share-Based Payment Accounting*, which requires that income taxes withheld upon settlement of share-based payment awards be classified as financing activities on the statement of cash flows.

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

	Year Ended December 31,				
(in thousands, except per share amounts)	**2012**	**2013**	**2014**	**2015**	**2016**
Statement of operations data:					
Operating revenues and other:					
Natural gas sales	$ 259,743	689,198	1,301,349	1,039,892	1,260,750
NGLs sales	3,719	111,663	328,323	264,483	432,992
Oil sales	1,520	20,584	107,080	70,753	61,319
Gathering, compression, and water handling and treatment	—	—	22,075	22,000	12,961
Marketing	—	—	53,604	176,229	393,049
Commodity derivative fair value gains (losses)	179,546	491,689	868,201	2,381,501	(514,181)
Gain on sale of assets	291,190	—	40,000	—	97,635
Total operating revenues and other	735,718	1,313,134	2,720,632	3,954,858	1,744,525
Operating expenses:					
Lease operating	6,243	9,439	29,341	36,011	50,090
Gathering, compression, processing, and transportation	91,094	218,428	461,413	659,361	882,838
Production and ad valorem taxes	20,210	50,481	87,918	78,325	66,588
Marketing	—	—	103,435	299,062	499,343
Exploration	14,675	22,272	27,893	3,846	6,862
Impairment of unproved properties	12,070	10,928	15,198	104,321	162,935
Depletion, depreciation, and amortization	102,026	233,876	477,896	709,763	809,873
Accretion of asset retirement obligations	101	1,065	1,271	1,655	2,473
General and administrative (including $365,280, $112,252, $97,877, and $102,421 of equity-based compensation expense in 2013, 2014, 2015, and 2016, respectively)	45,284	425,438	216,533	233,697	239,324
Contract termination and rig stacking	—	—	—	38,531	—
Total operating expenses	291,703	971,927	1,420,898	2,164,572	2,720,326
Operating income (loss)	444,015	341,207	1,299,734	1,790,286	(975,801)
Other Expenses:					
Equity in earnings of unconsolidated affiliate	—	—	—	—	485
Interest expense	(97,510)	(136,617)	(160,051)	(234,400)	(253,552)
Loss on early extinguishment of debt	—	(42,567)	(20,386)	—	(16,956)
Total other expenses	(97,510)	(179,184)	(180,437)	(234,400)	(270,023)
Income (loss) before income taxes and discontinued operations	346,505	162,023	1,119,297	1,555,886	(1,245,824)
Income tax (expense) benefit	(121,229)	(186,210)	(445,672)	(575,890)	496,376
Income (loss) from continuing operations	225,276	(24,187)	673,625	979,996	(749,448)
Discontinued operations:					
Income (loss) from results of operations and sale of discontinued operations, net of income tax	(510,345)	5,257	2,210	—	—
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(285,069)	(18,930)	675,835	979,996	(749,448)
Net income and comprehensive income attributable to noncontrolling interest	—	—	2,248	38,632	99,368
Net income (loss) attributable to Antero Resources Corporation	$ (285,069)	(18,930)	673,587	941,364	(848,816)
Earnings (loss) per common share:					
Continuing operations(1)	$ 0.86	(0.09)	2.56	3.43	(2.88)
Discontinued operations(1)	$ (1.95)	0.02	0.01	—	—
Total	$ (1.09)	(0.07)	2.57	3.43	(2.88)
Earnings (loss) per common share—assuming dilution:					
Continuing operations(1)	$ 0.86	(0.09)	2.56	3.43	(2.88)
Discontinued operations(1)	$ (1.95)	0.02	0.01	—	—
Total	$ (1.09)	(0.07)	2.57	3.43	(2.88)

(1) Earnings (loss) per common share and earnings (loss) per common share—assuming dilution for the years ended December 31, 2012 and 2013 were calculated as if the shares issued in our IPO on October 16, 2013 were outstanding for the entire period.

(in thousands)	Year Ended December 31, 2012	2013	2014	2015	2016
Balance sheet data (at period end):					
Cash and cash equivalents	$ 18,989	17,487	245,979	23,473	31,610
Other current assets	255,617	316,077	1,006,181	1,224,763	370,977
Total current assets	274,606	333,564	1,252,160	1,248,236	402,587
Natural gas properties, at cost (successful efforts method):					
Unproved properties	1,243,237	1,513,136	2,060,936	1,996,081	2,331,173
Producing properties	1,682,297	3,621,672	6,515,221	8,211,106	9,549,671
Water handling and treatment systems	6,835	231,684	421,012	565,616	744,682
Gathering systems and facilities	168,930	584,626	1,197,239	1,502,396	1,723,768
Other property and equipment	9,517	15,757	37,687	46,415	41,231
	3,110,816	5,966,875	10,232,095	12,321,614	14,390,525
Less accumulated depletion, depreciation, and amortization	(173,343)	(407,219)	(879,643)	(1,589,372)	(2,363,778)
Property and equipment, net	2,937,473	5,559,656	9,352,452	10,732,242	12,026,747
Other assets	398,231	695,321	934,766	2,135,015	1,826,216
Total assets	$ 3,610,310	6,588,541	11,539,378	14,115,493	14,255,550
Current liabilities	$ 313,676	553,038	894,732	707,270	817,388
Long-term indebtedness	1,435,575	2,053,959	4,328,433	4,668,782	4,703,973
Other long-term liabilities	187,322	382,884	842,383	1,452,763	1,005,611
Total equity	1,673,737	3,598,660	5,473,830	7,286,678	7,728,578
Total liabilities and equity	$ 3,610,310	6,588,541	11,539,378	14,115,493	14,255,550
Other financial data:					
Net cash provided by operating activities	$ 332,255	534,707	998,263	1,015,812	1,241,256
Net cash used in investing activities	$ (463,491)	(2,673,592)	(4,089,650)	(2,298,159)	(2,395,138)
Net cash provided by financing activities	$ 146,882	2,137,383	3,319,879	1,059,841	1,162,019
Capital expenditures	$ 1,682,549	2,671,573	4,086,568	2,347,909	2,495,429
Adjusted EBITDAX from continuing operations	$ 284,710	649,358	1,164,015	1,221,422	1,536,144
Adjusted EBITDAX from discontinued operations	$ 149,605	—	—	—	—
Total Adjusted EBITDAX	$ 434,315	649,358	1,164,015	1,221,422	1,536,144

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income or loss, including noncontrolling interests, before interest expense, interest income, derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), taxes, impairments, depletion, depreciation, amortization, and accretion, exploration expense, franchise taxes, equity-based compensation, gain or loss on early extinguishment of debt, contract termination and rig stacking costs, and gain or loss on sale of assets. "Adjusted EBITDAX," as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing, and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

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

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

- is used by our management team for various purposes, including as a measure of 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. Adjusted EBITDAX, as defined by our Credit Facility, is used by our lenders pursuant to covenants under our revolving credit facility and the indentures governing our senior notes.

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.

"Segment and consolidated Adjusted EBITDAX" is also used by our management team for various purposes, including as a measure of operating performance and as a basis for strategic planning and forecasting. Segment Adjusted EBITDAX is a non-GAAP financial measure that we define as operating income or loss before derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), impairments, depletion, depreciation, amortization, and accretion, exploration expense, franchise taxes, equity-based compensation, gain or loss on early extinguishment of debt, contract termination and rig stacking costs, gain or loss on sale of assets, and gain or loss on changes in the fair value of contingent acquisition consideration. Operating income represents net income, including noncontrolling interest, before interest expense, income taxes, and equity in earnings of unconsolidated affiliates, and is the most directly comparable GAAP financial measure to Segment Adjusted EBITDAX because we do not account for income tax expense or interest expense on a segment basis. The tables below represent a reconciliation of our operating income to Segment Adjusted EBITDAX for the years ended December 31, 2013, 2014, 2015, and 2016 (in thousands). Prior to 2013, we did not have any reportable segments and considered our gathering, processing, and water distribution and treatment operations to be ancillary to our exploration and production activities. Activities under our marketing segment commenced in 2014.

	Exploration and production	Gathering and processing	Water handling and treatment	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2013:					
Operating income (loss)	$ 371,066	(14,186)	16,355	(32,028)	341,207
Commodity derivative fair value gains	(491,689)	—	—	—	(491,689)
Gains on settled derivatives	163,570	—	—	—	163,570
Depletion, depreciation, amortization, and accretion	220,822	11,346	2,773	—	234,941
Impairment of unproved properties	10,928	—	—	—	10,928
Exploration expense	22,272	—	—	—	22,272
Equity-based compensation expense	340,931	15,931	8,418	—	365,280
State franchise taxes	2,849	—	—	—	2,849
Segment and consolidated Adjusted EBITDAX	$ 640,749	13,091	27,546	(32,028)	649,358

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2014:						
Operating income (loss)	$ 1,340,790	21,269	110,729	(49,831)	(123,223)	1,299,734
Commodity derivative fair value gains	(868,201)	—	—	—	—	(868,201)
Gains on settled derivatives	135,784	—	—	—	—	135,784
Gain on sale of assets	(40,000)	—	—	—	—	(40,000)
Depletion, depreciation, amortization, and accretion	425,955	36,972	16,240	—	—	479,167
Impairment of unproved properties	15,198	—	—	—	—	15,198
Exploration expense	27,893	—	—	—	—	27,893
Equity-based compensation expense	100,634	8,619	2,999	—	—	112,252
State franchise taxes	2,188	—	—	—	—	2,188
Contract termination and rig stacking	—	—	—	—	—	—
Segment and consolidated Adjusted EBITDAX	$ 1,140,241	66,860	129,968	(49,831)	(123,223)	1,164,015

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2015:						
Operating income (loss)	$ 1,844,255	99,476	67,073	(122,833)	(97,685)	1,790,286
Commodity derivative fair value gains	(2,381,501)	—	—	—	—	(2,381,501)
Gains on settled derivatives	856,572	—	—	—	—	856,572
Depletion, depreciation, amortization, and accretion	624,034	61,552	25,832	—	—	711,418
Impairment of unproved properties	104,321	—	—	—	—	104,321
Exploration expense	3,846	—	—	—	—	3,846
Gain (loss) on change in fair value of contingent acquisition consideration	(3,333)	3,333	—	—	—	—
Equity-based compensation expense	75,407	17,840	4,630	—	—	97,877
State franchise taxes	72	—	—	—	—	72
Contract termination and rig stacking	38,531	—	—	—	—	38,531
Segment and consolidated Adjusted EBITDAX	$ 1,162,204	182,201	97,535	(122,833)	(97,685)	1,221,422

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2016:						
Operating income (loss)	$ (981,446)	169,976	87,250	(106,294)	(145,287)	(975,801)
Commodity derivative fair value losses	514,181	—	—	—	—	514,181
Gains on settled derivatives	1,003,083	—	—	—	—	1,003,083
Gain on sale of assets	(93,776)	(3,859)	—	—	—	(97,635)
Depletion, depreciation, amortization, and accretion	711,600	70,847	29,899	—	—	812,346
Impairment of unproved properties	162,935	—	—	—	—	162,935
Exploration expense	6,862	—	—	—	—	6,862
Gain (loss) on change in fair value of contingent acquisition consideration	(16,489)	—	16,489	—	—	—
Equity-based compensation expense	76,372	19,714	6,335	—	—	102,421
Distributions from unconsolidated affiliates	—	7,702	—	—	—	7,702
State franchise taxes	50	—	—	—	—	50
Segment and consolidated Adjusted EBITDAX	$ 1,383,372	264,380	139,973	(106,294)	(145,287)	1,536,144

The following table represents a reconciliation of our net income (loss) from continuing operations, including noncontrolling interest, to total Segment and consolidated Adjusted EBITDAX from continuing operations, a reconciliation of our net income (loss) from discontinued operations to Adjusted EBITDAX from discontinued operations, and a reconciliation of our total Segment and consolidated Adjusted EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case, for the periods presented:

	Year ended December 31,				
(in thousands)	**2012**	**2013**	**2014**	**2015**	**2016**
Net income (loss) from continuing operations including noncontrolling interest	$ 225,276	(24,187)	673,625	979,996	(749,448)
Commodity derivative fair value (gains) losses(1)	(179,546)	(491,689)	(868,201)	(2,381,501)	514,181
Gains on settled derivatives(1)	178,491	163,570	135,784	856,572	1,003,083
Gain on sale of assets	(291,190)	—	(40,000)	—	(97,635)
Interest expense	97,510	136,617	160,051	234,400	253,552
Loss on early extinguishment of debt	—	42,567	20,386	—	16,956
Income tax expense (benefit)	121,229	186,210	445,672	575,890	(496,376)
Depletion, depreciation, amortization, and accretion	102,127	234,941	479,167	711,418	812,346
Impairment of unproved properties	12,070	10,928	15,198	104,321	162,935
Exploration expense	14,675	22,272	27,893	3,846	6,862
Equity-based compensation expense	—	365,280	112,252	97,877	102,421
Equity in earnings of unconsolidated affiliate	—	—	—	—	(485)
Distributions from unconsolidated affiliates	—	—	—	—	7,702
State franchise taxes	4,068	2,849	2,188	72	50
Contract termination and rig stacking	—	—	—	38,531	—
Adjusted EBITDAX from continuing operations	284,710	649,358	1,164,015	1,221,422	1,536,144
Net income (loss) from discontinued operations	(510,345)	5,257	2,210	—	—
Commodity derivative fair value gains	(46,358)	—	—	—	—
Gains on settled derivatives	92,166	—	—	—	—
Loss (gain) on sale of assets	795,945	(8,506)	(3,564)	—	—
Income tax expense (benefit)	(272,553)	3,249	1,354	—	—
Depletion, depreciation, amortization, and accretion	89,124	—	—	—	—
Impairment of unproved properties	962	—	—	—	—
Exploration expense	664	—	—	—	—
Adjusted EBITDAX from discontinued operations	149,605	—	—	—	—
Total Segment and consolidated Adjusted EBITDAX	434,315	649,358	1,164,015	1,221,422	1,536,144
Interest expense	(97,510)	(136,617)	(160,051)	(234,400)	(253,552)
Exploration expense	(15,339)	(22,272)	(27,893)	(3,846)	(6,862)
Changes in current assets and liabilities	9,887	41,914	17,947	39,498	(32,920)
State franchise taxes	(4,068)	(2,849)	(2,188)	(72)	(50)
Other non-cash items	4,970	5,173	6,433	(6,790)	(1,504)
Net cash provided by operating activities	$ 332,255	534,707	998,263	1,015,812	1,241,256

(1) The adjustments for the derivative fair value gains and losses and gains on settled derivatives have the effect of adjusting net income (loss) from operations for changes in the fair value of unsettled derivatives, which are recognized at the end of each accounting period. As a result, derivative gains included in the calculation of Adjusted EBITDAX only reflect derivatives which settled during the period.

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

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

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

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to 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, 2016, we held approximately 464,000 net acres in the southwestern core of the Marcellus Shale and approximately 152,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 210,000 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 235,000 net acres of our Marcellus Shale leasehold that may be prospective for the dry gas Utica Shale.

As of December 31, 2016, our estimated proved reserves were approximately 15.4 Tcfe, consisting of 9.4 Tcf of natural gas, 554 MMBbl of ethane, 404 MMBbl of C3+ NGLs, and 38 MMBbl of oil. This represents a 16% increase from December 31, 2015. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2016, we had approximately 3,630 potential horizontal well locations on our existing leasehold acreage which were classified as proved, probable, and possible.

We operate in the following industry segments: (i) the exploration, development, and production of natural gas, NGLs, and oil; (ii) gathering and processing; (iii) water handling and treatment; and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States.

Energy Industry Environment

In late 2014, global energy commodity prices declined precipitously as a result of several factors, including an increase in worldwide commodity supplies, a stronger U.S. dollar, relatively mild weather in large portions of the U.S. during the 2014 and 2015 winter months, and strong competition among oil producing countries for market share. Depressed commodity prices continued into 2015 and 2016, although a modest recovery has occurred in late 2016 and early 2017.

Spot prices for WTI declined significantly since June 2014 levels of approximately $106.00 per Bbl and have ranged from less than $30.00 per Bbl in February 2016 to approximately $53.00 per Bbl in February 2017. Spot prices for Henry Hub natural gas also declined significantly from approximately $4.40 per MMBtu in January 2014 to $2.00 per MMBtu in March 2016. Natural gas prices have recently recovered to approximately $3.00 per MMBtu in February 2017 due to increases in demand as a result of colder winter weather in many regions of the United States. Spot prices for propane, which is the largest portion of our NGLs sales, declined from approximately $1.55 per gallon in January 2014 to less than $0.35 per gallon in January 2016. Prices for propane have recovered to over $0.70 per gallon in February 2017.

In response to these market conditions and concerns about access to capital markets, many U.S. exploration and development companies significantly reduced their capital spending in 2015 and 2016. Our capital spending for drilling, completions, and land for 2016 was $2.1 billion, including drilling and completion costs of $1.3 billion and leasehold additions of $153 million, and acquisition costs of $593 million. Excluding acquisitions, this represents a decrease of 20% from our 2015 capital expenditures and a decrease of 52% from our 2014 capital expenditures. Although commodity prices have decreased in recent years, we have also experienced reductions in drilling and development costs as a result of decreased demand for oilfield services and increased efficiencies from improved drilling and completion technology and procedures. In addition to the reduction in our capital expenditures during 2016, we deferred the completion of 40 wells.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a field-by-field basis whenever events or changes in circumstances (such as the decline in commodity prices that began in 2014) indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeded the estimated undiscounted future cash flows (measured using strip prices at the end of a quarter), we would further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties. Due to the current commodity price environment, we compared the carrying values of our proved properties to estimated future cash flows. As estimated future cash flows remained higher than the carrying value of our properties at December 31, 2016, we did not further evaluate our proved properties for impairment. See "—Critical Accounting Policies and Estimates" for a discussion of such evaluation.

Source 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 resell our products to third parties overseas. During 2016 our production revenues were comprised of approximately 72% from the sale of natural gas and 28% 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, after processing, and oil.

To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to hedge future sales prices on a significant portion of our production. We enter into fixed price natural gas, NGLs, and oil swap contracts in which we receive or pay the difference between a fixed price and the variable market price received. In addition, we also use basis swap contracts in order to 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.

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

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

Principal Components of Our Cost Structure

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

- *Gathering, compression, processing and transportation.* These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low- and high-pressure gathering and compression systems held by Antero Midstream, as well as fees paid to third parties who operate low- and high-pressure gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced gas and to transport our 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) and at fixed per-unit rates established by federal, state, or local taxing authorities. Ad valorem taxes are paid based on the value of our property and equipment in service, as well as the value of our reserves.

- *Marketing expenses*. We purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity in order to utilize this excess capacity. 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 are marketing this excess capacity to third parties. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure capacity on major pipelines.

- *Exploration expense.* These are geological and geophysical costs and include seismic costs, costs related to unsuccessful leasing efforts, and costs of unsuccessful exploratory dry holes. We have not recorded any costs related to exploratory dry holes during the three years ended December 31, 2016.

- *Impairment of unproved and proved properties.* These costs include unproved property impairment and costs associated with lease expirations. We would also record impairment charges for proved properties if the carrying values were to exceed estimated future net cash flows. Through December 31, 2016, we have not recorded any impairment for proved properties.

- *Depletion, depreciation, and amortization.* Depletion, depreciation, and amortization, or DD&A, includes the systematic expensing of the capitalized costs incurred to acquire, explore, and develop natural gas, NGLs, and oil. As a "successful efforts" company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate these costs using the units of production method.

- *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, franchise taxes, audit and other professional fees, and legal compliance expenses. General and administrative expense also includes noncash equity-based compensation expense (see note 9 to the consolidated financial statements included elsewhere in this report).

- *Interest expense.* We finance a portion of our capital expenditures, working capital requirements, and acquisitions with borrowings under our revolving credit facilities, which have variable rates of interest based on LIBOR or the prime rate. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. At December 31, 2016, we had a fixed interest rate of 5.375% on our senior notes due 2021 having a principal balance of $1 billion, a fixed interest rate of 5.125% on our senior notes due 2022 having a principal balance of $1.1 billion, a fixed interest rate of 5.625% on our senior notes due 2023 having a principal balance of $750 million, and a fixed interest rate of 5.00% on our senior notes due 2025 having a principal balance of $600 million. Additionally, Antero Midstream had a fixed interest rate of 5.375% on its senior notes due 2024 having a principal balance of $650 million. We expect to continue to incur significant interest expense as we continue to grow our operations.

- *Income tax expense.* We are subject to state and federal income taxes, but are currently not in a tax paying position for regular federal income taxes, primarily due to the differences in the tax and financial statement treatment of oil and gas properties, and the deferral of unsettled commodity hedge gains for tax purposes until they are settled in an exchange of cash. We do pay some state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We have recorded deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income primarily from derivatives, oil and gas properties, and net operating loss carryforwards. At December 31, 2016, we had approximately $1.5 billion of U.S. federal net operating loss carryforwards (NOLs) that expire at various dates from 2024 through 2036, and approximately $1.4 billion of state NOLs that expire at various dates from 2017 through 2036. We recorded valuation allowances for deferred tax assets at December 31, 2016 of approximately $16 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

Year Ended December 31, 2015 Compared to Year Ended December 31, 2016

The Company has four operating segments: (1) the exploration, development, and production of natural gas, NGLs, and oil; (2) gathering and processing; (3) water handling and treatment; and (4) marketing of excess firm transportation capacity. Revenues from the gathering and processing and water handling and treatment operations are primarily derived from intersegment transactions for services provided to our exploration and production operations by Antero Midstream. Intersegment transactions that are eliminated include revenues from water handling and treatment services provided by Antero Midstream which are capitalized as proved property development costs by Antero. 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. The operating results and assets of the Company's reportable segments were as follows for the years ended December 31, 2015 and 2016 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2015:						
Sales and revenues:						
Third-party	$ 3,756,629	12,353	9,647	176,229	—	3,954,858
Intersegment	4,795	218,239	147,085	—	(370,119)	—
Total	$ 3,761,424	230,592	156,732	176,229	(370,119)	3,954,858
Operating expenses:						
Lease operating	$ 35,552	—	49,859	—	(49,400)	36,011
Gathering, compression, processing, and transportation	852,573	25,305	—	—	(218,517)	659,361
Depletion, depreciation, and amortization	622,379	61,552	25,832	—	—	709,763
General and administrative expense (before equity-based compensation)	108,268	22,608	6,128	—	(1,184)	135,820
Equity-based compensation expense	75,407	17,840	4,630	—	—	97,877
Other operating expenses	222,990	3,811	3,210	299,062	(3,333)	525,740
Total	1,917,169	131,116	89,659	299,062	(272,434)	2,164,572
Operating income (loss)	$ 1,844,255	99,476	67,073	(122,833)	(97,685)	1,790,286
Segment Adjusted EBITDAX (1)	1,162,204	182,201	97,535	(122,833)	(97,685)	1,221,422

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2016:						
Sales and revenues:						
Third-party	$ 1,334,656	16,028	792	393,049	—	1,744,525
Intersegment	18,324	291,916	281,475	—	(591,715)	—
Total	$ 1,352,980	307,944	282,267	393,049	(591,715)	1,744,525
Operating expenses:						
Lease operating	$ 50,651	—	136,386	—	(136,947)	50,090
Gathering, compression, processing, and transportation	1,146,221	28,098	—	—	(291,481)	882,838
Depletion, depreciation, and amortization	709,127	70,847	29,899	—	—	809,873
General and administrative expense (before equity-based compensation)	110,300	20,118	7,996	—	(1,511)	136,903
Equity-based compensation expense	76,372	19,714	6,335	—	—	102,421
Other operating expenses	241,755	(809)	14,401	499,343	(16,489)	738,201
Total	2,334,426	137,968	195,017	499,343	(446,428)	2,720,326
Operating income (loss)	$ (981,446)	169,976	87,250	(106,294)	(145,287)	(975,801)
Segment Adjusted EBITDAX (1)	1,383,372	264,380	139,973	(106,294)	(145,287)	1,536,144

(1) See "Item 6. Selected Financial Data" for a definition of Segment Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Segment Adjusted EBITDAX to operating income (loss).

The following tables set forth selected operating data for the year ended December 31, 2015 compared to the year ended December 31, 2016:

(in thousands)	Twelve Months Ended December 31, 2015	Twelve Months Ended December 31, 2016	Amount of Increase (Decrease)	Percent Change
Operating revenues and other:				
Natural gas sales	$ 1,039,892	$ 1,260,750	$ 220,858	21 %
NGLs sales	264,483	432,992	168,509	64 %
Oil sales	70,753	61,319	(9,434)	(13)%
Gathering, compression, and water handling and treatment	22,000	12,961	(9,039)	(41)%
Marketing	176,229	393,049	216,820	123 %
Commodity derivative fair value gains (losses)	2,381,501	(514,181)	(2,895,682)	*
Gain on sale of assets	—	97,635	97,635	*
Total operating revenues and other	3,954,858	1,744,525	(2,210,333)	(56)%
Operating expenses:				
Lease operating	36,011	50,090	14,079	39 %
Gathering, compression, processing, and transportation	659,361	882,838	223,477	34 %
Production and ad valorem taxes	78,325	66,588	(11,737)	(15)%
Marketing	299,062	499,343	200,281	67 %
Exploration	3,846	6,862	3,016	78 %
Impairment of unproved properties	104,321	162,935	58,614	56 %
Depletion, depreciation, and amortization	709,763	809,873	100,110	14 %
Accretion of asset retirement obligations	1,655	2,473	818	49 %
General and administrative (before equity-based compensation)	135,820	136,903	1,083	1 %
Equity-based compensation	97,877	102,421	4,544	5 %
Contract termination and rig stacking	38,531	—	(38,531)	*
Total operating expenses	2,164,572	2,720,326	555,754	26 %
Operating income (loss)	1,790,286	(975,801)	(2,766,087)	*
Other earnings (expenses):				
Equity in earnings of unconsolidated affiliate	—	485	485	*
Interest expense	(234,400)	(253,552)	(19,152)	8 %
Loss on early extinguishment of debt	—	(16,956)	(16,956)	*
Total other expenses	(234,400)	(270,023)	(35,623)	15 %
Income (loss) before income taxes	1,555,886	(1,245,824)	(2,801,710)	*
Income tax (expense) benefit	(575,890)	496,376	1,072,266	*
Net income (loss) and comprehensive income (loss) including noncontrolling interest	979,996	(749,448)	(1,729,444)	*
Net income and comprehensive income attributable to noncontrolling interest	38,632	99,368	60,736	157 %
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 941,364	$ (848,816)	$ (1,790,180)	*
Adjusted EBITDAX (1)	$ 1,221,422	$ 1,536,144	$ 314,722	26 %

(1) See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income including noncontrolling interest and net cash provided by operating activities.

* Not meaningful or applicable.

	Twelve Months Ended December 31, 2015	Twelve Months Ended December 31, 2016	Amount of Increase (Decrease)	Percent Change
Production data:				
Natural gas (Bcf)	439	505	66	15 %
C2 Ethane (MBbl)	201	6,396	6,195	3,090 %
C3+ NGLs (MBbl)	15,350	20,279	4,929	32 %
Oil (MBbl)	2,078	1,873	(205)	(10)%
Combined (Bcfe)	545	676	131	24 %
Daily combined production (MMcfe/d)	1,493	1,847	354	24 %
Average prices before effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 2.37	$ 2.50	$ 0.13	5 %
C2 Ethane (per Bbl)	$ 6.17	$ 8.28	$ 2.11	34 %
C3+ NGLs (per Bbl)	$ 17.15	$ 18.74	$ 1.59	9 %
Oil (per Bbl)	$ 34.05	$ 32.73	$ (1.32)	(4)%
Combined (per Mcfe)	$ 2.52	$ 2.60	$ 0.08	3 %
Average realized prices after effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 4.15	$ 4.39	$ 0.24	6 %
C2 Ethane (per Bbl)	$ 6.17	$ 8.28	$ 2.11	34 %
C3+ NGLs (per Bbl)	$ 20.76	$ 21.03	$ 0.27	1 %
Oil (per Bbl)	$ 42.38	$ 32.73	$ (9.65)	(23)%
Combined (per Mcfe)	$ 4.10	$ 4.08	$ (0.02)	*
Average Costs (per Mcfe):				
Lease operating	$ 0.07	$ 0.07	$ —	*
Gathering, compression, processing, and transportation	$ 1.21	$ 1.31	$ 0.10	8 %
Production and ad valorem taxes	$ 0.14	$ 0.10	$ (0.04)	(29)%
Marketing, net	$ 0.23	$ 0.16	$ (0.07)	(30)%
Depletion, depreciation, amortization, and accretion	$ 1.31	$ 1.20	$ (0.11)	(8)%
General and administrative (before equity-based compensation)	$ 0.25	$ 0.20	$ (0.05)	(20)%

(2) 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, 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.

Discussion of Consolidated Exploration and Production Results for the Year Ended December 31, 2015 Compared to the Year Ended December 31, 2016

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $1.4 billion for the year ended December 31, 2015 to $1.8 billion for the year ended December 31, 2016, an increase of $380 million, or 28%. Our production increased by 24% over that same period, from 545 Bcfe, or 1,493 MMcfe per day, for the year ended December 31, 2015 to 676 Bcfe, or 1,847 MMcfe per day, for the year ended December 31, 2016. Net equivalent prices before the effects of settled derivative gains increased from $2.52 per Mcfe for the year ended December 31, 2015 to $2.60 per Mcfe for the year ended December 31, 2016, an increase of 3%. Average prices for natural gas, ethane, and C3+ NGLs all increased from 2015 levels, whereas average prices for oil declined from 2015 levels. Net equivalent prices after the effects of gains on settled derivatives decreased nominally from $4.10 per Mcfe for the year ended December 31, 2015 to $4.08 for the year ended December 31, 2016.

Increased production volumes accounted for an approximate $330 million increase in year-over-year product revenues (calculated as the combined change in year-to-year volumes times the prior year average price), and increases in our equivalent prices, excluding the effects of derivative settlements, accounted for an approximate $50 million increase in year-over-year product revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our drilling and completion program.

Commodity derivative fair value gains. To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into derivative contracts using fixed for variable swap 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, and 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, 2015 and 2016, our hedges resulted in derivative fair value gains (losses) of $2.4 billion and $(514) million, respectively. The derivative fair value gains included $857 million and $1.0 billion of gains on cash settled derivatives for the years ended December 31, 2015 and 2016, respectively. 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. Derivative asset or liability positions at the end of any accounting period may reverse to the extent commodity futures 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.

Gathering, compression, and water handling and treatment revenues. Gathering, compression, and water handling and treatment revenues decreased from $22 million for the year ended December 31, 2015 to $13 million for the year ended December 31, 2016, primarily attributable to the provision of water handling and treatment services to wells in which we held a higher working interest in 2016 than the wells to which such services were provided in 2015. Fees for water handling and treatment services provided to us by Antero Midstream are eliminated in consolidation. The amounts that are not eliminated represent the portion of such fees that are charged to outside working interest owners in Company-operated wells, as well as fees charged to other third parties for services provided by Antero Midstream.

Gain on sale of assets. In December 2016, we closed the sale of approximately 17,000 net acres primarily located in Washington and Westmoreland Counties, Pennsylvania. The acreage was outside of the Company's infrastructure build-out and was not expected to be developed in the near future. Included in the sale were two Antero-operated producing wells and a gathering pipeline belonging to Antero Midstream. Total proceeds from the sale were $169.8 million (subject to customary purchase price adjustments). As a result of the sale, the Company recognized a gain on the sale of assets of $99.0 million for the year ended December 31, 2016. We also recognized net losses of approximately $1.4 million that were attributable to other asset sales during the year ended December 31, 2016, resulting in a net gain on sales of assets of $97.6 million.

Lease operating expenses. Lease operating expenses increased from $36 million for the year ended December 31, 2015 to $50 million for the year ended December 31, 2016, an increase of 39%. The increase is primarily a result of an increase in production and the number of producing wells. On a per unit basis, lease operating expenses remained constant at $0.07 per Mcfe for the years ended December 31, 2015 and 2016. Lease operating expenses are expected to slowly increase on a per unit basis as maturing properties make up a larger proportion of our production base and average production per well declines.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $659 million for the year ended December 31, 2015 to $883 million for the year ended December 31, 2016. The increase in these expenses is a result of the increase in production and the related firm transportation costs, and third-party gathering, compression, and processing expenses. On a per-unit basis, total gathering, compression, processing, and transportation expenses increased by 8%, from $1.21 per Mcfe for the year ended December 31, 2015 to $1.31 per Mcfe for the year ended December 31, 2016, primarily due to higher per-unit transportation costs incurred on new pipelines that were placed in service in late 2015. Substantially all of the new pipelines currently deliver our gas to better price indices or sales contracts resulting in higher realized gas prices for the period.

Production and ad valorem tax expense. Total production and ad valorem taxes decreased from $78 million for the year ended December 31, 2015 to $67 million for the year ended December 31, 2016 as a result of a decrease in the estimate of ad valorem taxes payable by Antero Midstream, as well as the July 1, 2016 termination of a West Virginia production tax surcharge for workers' compensation funding. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging decreased from 5.7% for the year ended December 31, 2015 to 3.8% for the year ended December 31, 2016 primarily attributable to the termination of the West Virginia workman's compensation production tax. Additionally, as production in Ohio increases at a higher rate than West Virginia, severance taxes as a percentage of revenue decrease due to lower severance tax rates in Ohio as compared to West Virginia.

Exploration expense. Exploration expense of $3.8 million for the year ended December 31, 2015 increased to $6.9 million for the year ended December 31, 2016. These amounts represent expenses incurred for unsuccessful lease acquisitions.

Impairment of unproved properties. Impairment of unproved properties increased from $104 million for the year ended December 31, 2015 to $163 million for the year ended December 31, 2016, primarily due to the impairment of soon-to-expire Ohio Utica leases which we decided not to retain and develop. We charge impairment expense for expired or soon to be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks, or future plans to develop the acreage.

DD&A. DD&A increased from $710 million for the year ended December 31, 2015 to $810 million for the year ended December 31, 2016, primarily because of increased production. DD&A per Mcfe decreased by 8%, from $1.31 per Mcfe during the year ended December 31, 2015 to $1.20 per Mcfe during the year ended December 31, 2016, primarily due to decreases in our per-unit development costs, in part due to recent well cost reductions and drilling and completion efficiencies that we have achieved.

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 (such as the decline in commodity prices since late 2014) indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeded the estimated undiscounted future net cash flows (measured using futures prices at the end of a quarter), we would further evaluate our proved properties and record an impairment charge if the carrying amount of our proved properties exceeded the estimated fair value of the properties. At December 31, 2016, we compared the carrying values of our proved properties to estimated future net cash flows. As estimated future net cash flows were higher than the carrying value of our proved properties at December 31, 2016, we did not further evaluate our proved properties for impairment.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased nominally from $136 million for the year ended December 31, 2015 to $137 million for the year ended December 31, 2016, primarily due to increases in employee salary and benefits expenses as a result of an increase in the number of employees, partially offset by decreases in legal costs that were incurred in connection with the sale of Antero's water handling and treatment assets to Antero Midstream during the year ended December 31, 2015. On a per unit basis, general and administrative expense before equity-based compensation decreased by 20%, from $0.25 per Mcfe during the year ended December 31, 2015 to $0.20 per Mcfe during the year ended December 31, 2016, primarily due to our 24% increase in production. We had 480 employees as of December 31, 2015 and 528 employees as of December 31, 2016.

Noncash equity-based compensation expense increased from $98 million for the year ended December 31, 2015 to $102 million for the year ended December 31, 2016 as a result of a $38 million decrease in amortization of expense related to the vesting of profits interests, partially offset by a $32 million increase in equity-based compensation related to restricted stock unit awards and a $10 million increase in equity-based compensation related to other equity awards. See note 9 to the consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Contract termination and rig stacking. We incurred contract termination and rig stacking costs of $39 million during the year ended December 31, 2015. Of this total, $28 million was related to the buy-back and termination of a firm sales contract which was priced at an unfavorable Dominion South index. The remaining $11 million represents fees incurred upon the delay or cancellation of drilling contracts with third-party contractors in the first quarter of 2015 in order to align our drilling and completion activity level with our 2015 capital budget. There were no such costs incurred during the year ended December 31, 2016.

Equity in earnings of unconsolidated affiliate. In May 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline. Equity in earnings of unconsolidated affiliate of $0.5 million for the year ended December 31, 2016 represents the portion of the pipeline's net income which is allocated to Antero Midstream based on its equity interest in the pipeline. The Company did not hold any unconsolidated equity investments during the year ended December 31, 2015.

Interest expense. Interest expense increased from $234 million for the year ended December 31, 2015 to $254 million for the year ended December 31, 2016 due to an increase in average total indebtedness outstanding during the year. Interest expense includes approximately $10 million and $12 million of non-cash amortization of deferred financing costs for the years ended December 31, 2015 and 2016, respectively.

Loss on early extinguishment of debt. On December 30, 2016, we satisfied and discharged our obligations with respect to our outstanding 6.00% senior notes due 2020, resulting in a loss on early redemption of $17 million for the year ended December 31, 2016.

Income tax (expense) benefit. Income tax (expense) benefit changed from a deferred tax expense of $576 million for the year ended December 31, 2015 to a deferred tax benefit of $496 million for the year ended December 31, 2016. The deferred tax benefit in 2016 results from the net loss incurred. The effect of state tax rates, state tax apportionment, and the noncontrolling interest in Antero Midstream largely account for the difference between the federal tax rate of 35% and the rate at which the income tax benefit was provided for the year ended December 31, 2016.

At December 31, 2016, we had approximately $1.5 billion of U.S. federal NOLs that expire at various dates from 2024 through 2036, and approximately $1.4 billion of state NOLs that expire at various dates from 2017 through 2036. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs. Such legislation could significantly affect our future taxable position, if passed. The impact of any change will be recorded in the period that any such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. At December 31, 2016, our financial statements did not include any unrecognized tax benefits.

Adjusted EBITDAX. Adjusted EBITDAX increased from $1.22 billion for the year ended December 31, 2015 to $1.54 billion for the year ended December 31, 2016, an increase of 26%. The increase in Adjusted EBITDAX was primarily due to a 24% increase in production, net of the related increases in cash operating and general and administrative expenses. See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) from continuing operations including noncontrolling interest and net cash provided by operating activities.

Discussion of Segment Results for the Year Ended December 31, 2015 Compared to the Year Ended December 31, 2016

Gathering and processing. Revenue for the gathering and processing segment increased from $231 million for the year ended December 31, 2015 to $308 million for the year ended December 31, 2016, an increase of $77 million, or 34%. Gathering revenues increased by $52 million from the prior year and compression revenues increased by $21 million as additional wells on production increased throughput volumes. Additionally, the gathering and processing segment recognized a $4 million gain on the sale of assets related to its gathering system that was sold in conjunction with the exploration and production segment's acreage sale in Pennsylvania in December 2016. Total operating expenses related to the gathering and processing segment increased from $131 million for the year ended December 31, 2015 to $138 million for the year ended December 31, 2016 as a result of the increased throughput volumes, as well as increases in depreciation expense due to a larger base of gathering assets.

Water handling and treatment. Revenue for the water handling and treatment segment increased from $157 million for the year ended December 31, 2015 to $282 million for the year ended December 31, 2016, an increase of $125 million or 80%. The increase was due to revenues generated from other fluid handling services that commenced in the fourth quarter of 2015, as well as increased use of the water systems as a result of increased completion activity. The volume of water delivered through the fresh water distribution systems increased from 35.0 MMBbls for the year ended December 31, 2015 to 45.1 MMBbls for the year ended December 31, 2016. Operating expenses for the water handling and treatment segment increased from $90 million for the year ended December 31, 2015 to $195 million for the year ended December 31, 2016 as a result of expenses incurred by the commencement of other fluid handling services and an increase in depreciation expense due to a larger base of fresh water distribution assets, partially offset by a decrease in expenses related to water distribution as a result of the decreased use of the water systems.

Marketing. Where permitted, we purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity, or engage third parties to conduct these activities on our behalf, in order to optimize the revenues from these transportation agreements. We have entered into long-term firm transportation agreements for a significant portion of our current and expected future production in order to secure guaranteed capacity to favorable markets. Marketing revenues of $176 million and $393 million and expenses of $299 million and $499 million for the years ended December 31, 2015 and 2016, respectively, relate to these activities. Net losses on our marketing activities were $123 million and $106 million for the years ended December 31, 2015 and 2016, respectively. Marketing costs 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 $132 million and $114 million for the years ended December 31, 2015 and 2016, respectively, related to unutilized excess capacity which decreased primarily due to greater utilization of our reservation capacity on an ethane pipeline that was considered excess capacity in 2015.

Based on current projections for our 2017 annual production levels, we estimate that we could incur total annual net marketing expense of $60 million to $105 million in 2017 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 between various indicies. In years subsequent to 2017, our commitments and obligations under firm transportation agreements continue to increase. As a result, our net marketing expense could increase depending on our utilization of our transportation capacity based on future production and how much, if any, future excess transportation can be marketed to third parties.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2015

The operating results and assets of the Company's reportable segments were as follows for the years ended December 31, 2014 and 2015 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2014:						
Sales and revenues:						
Third-party	$ 2,644,953	6,810	15,265	53,604	—	2,720,632
Intersegment	195	88,936	156,660	—	(245,791)	—
Total	$ 2,645,148	95,746	171,925	53,604	(245,791)	2,720,632
Operating expenses:						
Lease operating	$ 28,041	—	34,737	—	(33,437)	29,341
Gathering, compression, processing, and transportation	536,879	13,497	—	—	(88,963)	461,413
Depletion, depreciation, and amortization	424,684	36,972	16,240	—	—	477,896
General and administrative expense (before equity-based compensation)	85,701	13,416	5,332	—	(168)	104,281
Equity-based compensation expense	100,634	8,619	2,999	—	—	112,252
Other operating expenses	128,419	1,973	1,888	103,435	—	235,715
Total	1,304,358	74,477	61,196	103,435	(122,568)	1,420,898
Operating income (loss)	$ 1,340,790	21,269	110,729	(49,831)	(123,223)	1,299,734
Segment Adjusted EBITDAX (1)	1,140,241	66,860	129,968	(49,831)	(123,223)	1,164,015

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2015:						
Sales and revenues:						
Third-party	$ 3,756,629	12,353	9,647	176,229	—	3,954,858
Intersegment	4,795	218,239	147,085	—	(370,119)	—
Total	$ 3,761,424	230,592	156,732	176,229	(370,119)	3,954,858
Operating expenses:						
Lease operating	$ 35,552	—	49,859	—	(49,400)	36,011
Gathering, compression, processing, and transportation	852,573	25,305	—	—	(218,517)	659,361
Depletion, depreciation, and amortization	622,379	61,552	25,832	—	—	709,763
General and administrative expense (before equity-based compensation)	108,268	22,608	6,128	—	(1,184)	135,820
Equity-based compensation expense	75,407	17,840	4,630	—	—	97,877
Other operating expenses	222,990	3,811	3,210	299,062	(3,333)	525,740
Total	1,917,169	131,116	89,659	299,062	(272,434)	2,164,572
Operating income (loss)	$ 1,844,255	99,476	67,073	(122,833)	(97,685)	1,790,286
Segment Adjusted EBITDAX (1)	1,162,204	182,201	97,535	(122,833)	(97,685)	1,221,422

(1) See "Item 6. Selected Financial Data" for a definition of Segment Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Segment Adjusted EBITDAX to operating income (loss).

The following tables set forth selected operating data for the year ended December 31, 2014 compared to the year ended December 31, 2015:

(in thousands)	Year ended December 31, 2014	2015	Amount of Increase (Decrease)	Percent Change
Operating revenues and other:				
Natural gas sales	$ 1,301,349	$ 1,039,892	$ (261,457)	(20)%
NGLs sales	328,323	264,483	(63,840)	(19)%
Oil sales	107,080	70,753	(36,327)	(34)%
Gathering, compression, and water handling and treatment	22,075	22,000	(75)	— %
Marketing	53,604	176,229	122,625	229 %
Commodity derivative fair value gains	868,201	2,381,501	1,513,300	174 %
Gain on sale of assets	40,000	—	(40,000)	*
Total operating revenues and other	2,720,632	3,954,858	1,234,226	45 %
Operating expenses:				
Lease operating	29,341	36,011	6,670	23 %
Gathering, compression, processing, and transportation	461,413	659,361	197,948	43 %
Production and ad valorem taxes	87,918	78,325	(9,593)	(11)%
Marketing	103,435	299,062	195,627	189 %
Exploration	27,893	3,846	(24,047)	(86)%
Impairment of unproved properties	15,198	104,321	89,123	586 %
Depletion, depreciation, and amortization	477,896	709,763	231,867	49 %
Accretion of asset retirement obligations	1,271	1,655	384	30 %
General and administrative (before equity-based compensation)	104,281	135,820	31,539	30 %
Equity-based compensation	112,252	97,877	(14,375)	(13)%
Contract termination and rig stacking	—	38,531	38,531	*
Total operating expenses	1,420,898	2,164,572	743,674	52 %
Operating income	1,299,734	1,790,286	490,552	38 %
Other Expenses:				
Interest expense	(160,051)	(234,400)	(74,349)	46 %
Loss on early extinguishment of debt	(20,386)	—	20,386	*
Total other expenses	(180,437)	(234,400)	(53,963)	30 %
Income from continuing operations before income taxes and discontinued operations	1,119,297	1,555,886	436,589	39 %
Income tax expense	(445,672)	(575,890)	(130,218)	29 %
Income from continuing operations	673,625	979,996	306,371	45 %
Income from discontinued operations	2,210	—	(2,210)	*
Net income and comprehensive income including noncontrolling interest	675,835	979,996	304,161	45 %
Net income and comprehensive income attributable to noncontrolling interest	2,248	38,632	36,384	1,619 %
Net income and comprehensive income attributable to Antero Resources Corporation	$ 673,587	$ 941,364	$ 267,777	40 %
Adjusted EBITDAX (1)	$ 1,164,015	$ 1,221,422	$ 57,407	5 %

(3) See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income from continuing operations including noncontrolling interest and net cash provided by operating activities.

* Not meaningful or applicable.

	Year ended December 31, 2014	Year ended December 31, 2015	Amount of Increase (Decrease)	Percent Change
Production data:				
Natural gas (Bcf)	317	439	122	39 %
NGLs (MBbl)	7,102	15,550	8,448	119 %
Oil (MBbl)	1,311	2,078	767	58 %
Combined (Bcfe)	368	545	177	48 %
Daily combined production (MMcfe/d)	1,007	1,493	486	48 %
Average prices before effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 4.10	$ 2.37	$ (1.73)	(42)%
NGLs (per Bbl)	$ 46.23	$ 17.01	$ (29.22)	(63)%
Oil (per Bbl)	$ 81.65	$ 34.05	$ (47.60)	(58)%
Combined (per Mcfe)	$ 4.73	$ 2.52	$ (2.21)	(47)%
Average realized prices after effects of derivative settlements(2):				
Natural gas (per Mcf)	$ 4.52	$ 4.15	$ (0.37)	(8)%
NGLs (per Bbl)	$ 46.23	$ 20.57	$ (25.66)	(56)%
Oil (per Bbl)	$ 84.66	$ 42.38	$ (42.28)	(50)%
Combined (per Mcfe)	$ 5.10	$ 4.10	$ (1.00)	(20)%
Average Costs (per Mcfe):				
Lease operating	$ 0.08	$ 0.07	$ (0.01)	(13)%
Gathering, compression, processing, and transportation	$ 1.26	$ 1.21	$ (0.05)	(4)%
Production and ad valorem taxes	$ 0.24	$ 0.14	$ (0.10)	(42)%
Marketing, net	$ 0.14	$ 0.23	$ 0.09	64 %
Depletion, depreciation, amortization, and accretion	$ 1.30	$ 1.31	$ 0.01	1 %
General and administrative (before equity-based compensation)	$ 0.28	$ 0.25	$ (0.03)	(11)%

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 for derivatives, 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.

Discussion of Consolidated Exploration and Production Results for the Year Ended December 31, 2014 Compared to the Year Ended December 31, 2015

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil decreased from $1.7 billion for the year ended December 31, 2014 to $1.4 billion for the year ended December 31, 2015, a decrease of $362 million, or 21%. Our production increased by 48% over that same period, from 368 Bcfe, or 1,007 MMcfe per day, for the year ended December 31, 2014 to 545 Bcfe, or 1,493 MMcfe per day, for the year ended December 31, 2015. Net equivalent prices before the effects of settled derivative gains decreased from $4.73 per Mcfe for the year ended December 31, 2014 to $2.52 for the year ended December 31, 2015, a decrease of 47%. Average prices for natural gas, NGLs, and oil all declined from 2014 levels. Net equivalent prices after the effects of gains on settled derivatives decreased from $5.10 per Mcfe for the year ended December 31, 2014 to $4.10 per Mcfe for the year ended December 31, 2015.

Increased production volumes accounted for an approximate $839 million increase in year-over-year product revenues (calculated as the combined change in year-to-year volumes times the prior year average price), and decreases in our equivalent prices, excluding the effects of derivative settlements, accounted for an approximate $1.2 billion decrease in year-over-year product revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our ongoing drilling and completion program.

Commodity derivative fair value gains. To achieve more predictable cash flows, and to reduce our exposure to price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas, NGLs, and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment, and 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, 2014 and 2015, our hedges resulted in derivative fair value gains of $868 million and $2.4 billion, respectively. The derivative fair value gains included $136 million and $857 million of gains on cash settled derivatives for the years ended December 31, 2014 and 2015, respectively. 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. Derivative asset or liability positions at the end of any accounting period may reverse to the extent natural gas, NGLs, and oil futures 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.

Gathering, compression, and water handling and treatment. Gathering, compression, and water handling and treatment revenues remained constant at $22 million for the years ended December 31, 2014 and 2015, primarily due to increased throughput from production, offset by decreased use of the fresh water distribution systems. These amounts represent the portion of such fees that are charged to outside working interest owners in Company-operated wells, as well as fees charged to other third parties for water provided by the Company or usage of Antero Midstream's gathering pipelines.

Gain on sale of assets. In 2012, we closed the sale of a portion of our Marcellus Shale gathering system assets in West Virginia along with exclusive rights to gather our gas for a 20 year period within an area of dedication to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together "Crestwood"). Under the terms of the contract, we could earn additional proceeds of $40 million if certain volume thresholds were met by December 31, 2014. As the volume thresholds were fully met during 2014, we recorded an additional $40 million of gain on the sale of assets in 2014, which was paid by Crestwood in the first quarter of 2015.

Lease operating expenses. Lease operating expenses increased from $29 million for the year ended December 31, 2014 to $36 million for the year ended December 31, 2015, an increase of 23%. The increase is a result of an increase in production and the number of producing wells. On a per unit basis, lease operating expenses decreased from $0.08 per Mcfe for the year ended December 31, 2014 to $0.07 per Mcfe for the year ended December 31, 2015 as production from new wells caused overall production to increase at a faster rate than our lease operating costs. Lease operating expenses are expected to slowly increase on a per unit basis as maturing properties make up a larger proportion of our production base and average production per well declines.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $461 million for the year ended December 31, 2014 to $659 million for the year ended December 31, 2015. The increase in these expenses was a result of the increase in production and related firm transportation costs, and third-party gathering, compression and processing expenses. On a per-unit basis, total gathering, compression, processing and transportation expenses decreased by 4%, from $1.26 per Mcfe for the year ended December 31, 2014 to $1.21 for the year ended December 31, 2015, primarily as a result of decreases in fuel costs as compared to the prior year due to lower natural gas prices.

Production and ad valorem tax expense. Total production and ad valorem taxes decreased from $88 million for the year ended December 31, 2014 to $78 million for the year ended December 31, 2015, primarily as a result of a decrease in the estimate of ad valorem taxes payable by Antero Midstream, partially offset by increases in ad valorem taxes due to wells placed on-line during 2015. Production and ad valorem taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging increased from 5.1% for the year ended December 31, 2014 to 5.7% for the year ended December 31, 2015 as a result of certain volumetric production taxes in West Virginia that increased as a percentage of revenues as price declines were offset by a decrease in ad valorem taxes on midstream assets.

Exploration expense. Exploration expense of $28 million for the year ended December 31, 2014 decreased to $4 million for the year ended December 31, 2015. These amounts represent expenses incurred due to unsuccessful lease acquisitions.

Impairment of unproved properties. Impairment of unproved properties increased from $15 million for the year ended December 31, 2014 to $104 million for the year ended December 31, 2015, primarily due to the impairment of several groups of leases that we decided not to retain and develop. We charge impairment expense for expired or soon to be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage.

DD&A. DD&A increased from $478 million for the year ended December 31, 2014 to $710 million for the year ended December 31, 2015, primarily because of increased production. DD&A per Mcfe increased by 1%, from $1.30 per Mcfe during the year ended December 31, 2014 to $1.31 per Mcfe during the year ended December 31, 2015, primarily due to increased depreciation on midstream and water assets, partially offset by proved developed reserves increasing at a faster rate than the corresponding cost additions from wells completed during the year ended December 31, 2015.

We evaluate the carrying amount of our proved natural gas, NGLs, and oil properties for impairment on a field-by-field basis whenever events or changes in circumstances (such as the decline in commodity prices during 2015) indicate that a property's carrying amount may not be recoverable. No impairment expenses were recorded for the years ended December 31, 2014 and 2015 for proved properties.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased from $104 million for the year ended December 31, 2014 to $136 million for the year ended December 31, 2015, primarily as a result of increased staffing levels and related salary and benefits expenses, as well as increases in legal and other general corporate expenses, all of which are due to our increase in development activities and production levels. On a per unit basis, general and administrative expense before equity-based compensation decreased by 11%, from $0.28 per Mcfe during the year ended December 31, 2014 to $0.25 per Mcfe during the year ended December 31, 2015, primarily due to a 48% increase in production. We had 444 employees as of December 31, 2014 and 480 employees as of December 31, 2015.

Noncash equity-based compensation expense decreased from $112 million for the year ended December 31, 2014 to $98 million for the year ended December 31, 2015 as a result of a $46 million decrease in amortization expense related to the vesting of profits interests, partially offset by a $32 million increase in equity-based compensation related to restricted stock unit, stock option, and Antero Midstream phantom unit awards. See note 9 to the consolidated financial statements included elsewhere in this report for more information on equity-based compensation awards.

Contract termination and rig stacking. We incurred contract termination and rig stacking costs of $39 million during the year ended December 31, 2015. Of this total, $28 million was related to the buy-back and termination of a firm sales contract which was priced at an unfavorable Dominion South index. The remaining $11 million represents fees incurred upon the delay or cancellation of drilling contracts with third-party contractors in the first quarter of 2015 in order to align our drilling and completion activity level with our 2015 capital budget.

Interest expense. Interest expense increased from $160 million for the year ended December 31, 2014 to $234 million for the year ended December 31, 2015, due to increased indebtedness. Interest expense included approximately $8 million and $10 million of non-cash amortization of deferred financing costs for the years ended December 31, 2014 and 2015, respectively.

Loss on early extinguishment of debt. On May 23, 2014, we redeemed our outstanding 7.25% senior notes due 2019, resulting in a loss on early redemption of $20 million for the year ended December 31, 2014.

Income tax expense. Income tax expense increased from $446 million for the year ended December 31, 2014 to $576 million for the year ended December 31, 2015 because of the increase in pre-tax income year-over-year. Equity-based compensation expense of $84 million in 2014 and $38 million in 2015 related to the vested profits interests charge is not deductible for federal or state income taxes and, along with the effect of state taxes, largely accounted for the difference between the federal tax rate of 35% and the rates at which income tax expense was provided for the years ended December 31, 2014 and 2015.

Income from discontinued operations. In 2012, the Company sold its Piceance Basin assets in Colorado and its Arkoma Basin assets in Oklahoma. Total proceeds from the sales, including liquidation of related hedge positions, were approximately $843 million and pre-tax losses on the asset sales of approximately $796 million were recorded in 2012. Pre-tax losses were adjusted downward in 2014 by $3.6 million for the resolution of certain liabilities recorded at the time of the sales and settlement of final contractual purchase price adjustments.

Adjusted EBITDAX. Adjusted EBITDAX increased from $1.16 billion for the year ended December 31, 2014 to $1.22 billion for the year ended December 31, 2015, an increase of 5%. The increase in Adjusted EBITDAX was primarily due to a 48% increase in production, which was partially offset by a 20% decrease in the average per Mcfe price received after the impact of cash settled derivatives, net of the related increases in cash operating and general and administrative expenses. See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of Adjusted EBITDAX (a non-GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss) from continuing operations including noncontrolling interest and net cash provided by operating activities.

Discussion of Segment Results for the Year Ended December 31, 2014 Compared to the Year Ended December 31, 2015

Gathering and processing. Revenue for the gathering and processing segment increased from $96 million for the year ended December 31, 2014 to $231 million for the year ended December 31, 2015, an increase of $135 million, or 141%. Gathering revenues increased by $112 million year-over-year and compression revenues increased by $23 million as additional wells on production increased throughput volumes. Total operating expenses related to the gathering and processing segment increased from $74 million in 2014 to $131 million in 2015 as a result of the increased throughput volumes, as well as increases in depreciation expense due to a larger base of gathering assets.

Water handling and treatment. Revenue for the water handling and treatment segment decreased from $172 million for the year ended December 31, 2014 to $157 million for the year ended December 31, 2015, a decrease of $15 million or 9%. The decrease was due to decreased use of the water systems in our completion activities as a result of the deferral of some well completions, partially offset by revenues generated from the commencement of other fluid handling services in late 2015. The volume of water delivered through the fresh water distribution systems decreased from 48.3 MMBbls for the year ended December 31, 2014 to 35.0 MMBbls for the year ended December 31, 2015. Operating expenses for the water handling and treatment segment increased from $61 million for the year ended December 31, 2014 to $90 million for the year ended December 31, 2015 as a result of expenses incurred by the commencement of other fluid handling services and an increase in depreciation expense due to a larger base of fresh water distribution assets, partially offset by a decrease in operating expenses related to fresh water distribution as a result of the decreased use of the fresh water distribution systems.

Marketing. Marketing revenues increased from $54 million for the year ended December 31, 2014 to $176 million for the year ended December 31, 2015. Marketing expenses increased from $103 million for the year ended December 31, 2014 to $299 million for the year ended December 31, 2015. Net losses on our marketing activities were $49 million and $123 million for the years ended December 31, 2014 and 2015. Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This included firm transportation costs of $59 million and $132 million for the years ended December 31, 2014 and 2015, respectively, related to unutilized excess capacity which increased due to new firm transportation agreements. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity to favorable markets.

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt and equity securities, borrowings under our revolving credit facility, asset sales, and net cash provided by operating activities. During 2016, we raised capital from a public offering and a private placement of our common stock resulting in total net proceeds of $1.0 billion, the issuance of $600 million of 5.00% senior notes due 2025, and the sale of $178 million of Antero Midstream common units owned by Antero. Cash provided by operating activities during 2016 was $1.24 billion. During 2016, Antero Midstream raised capital from the issuance of $650 million of 5.375% senior notes due 2024 and the sale of $65 million of common units under its equity distribution agreement.

Historically, our primary use of cash has been for the exploration, development, and acquisition of natural gas, NGL, and oil properties, as well as for development of gathering, compression, and fresh water handling and waste water treatment infrastructure. Additionally, in August 2015, we commenced development of an advanced waste water treatment complex in West Virginia, which was contributed to Antero Midstream in connection with the contribution of our water handling and treatment assets in September 2015. 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 proved reserves and production will be highly dependent on the capital resources available to us.

As of December 31, 2016, we had 3,630 potential horizontal well locations in our proved, probable, and possible reserve base, which will take many years to develop. More specifically, our proved undeveloped reserves will require an estimated $3.8 billion of development capital over the next five years in order to fully develop the properties associated with our proved reserves. We believe that all or a significant portion of this capital requirement will be funded out of operating cash flows. For a discussion of the risks related to development of our proved undeveloped reserves, see "Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced."

Antero's revolving credit facility has a borrowing base of $4.75 billion and current lender commitments of $4.0 billion. The borrowing base is redetermined every six months based on reserves, 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 2017. For a discussion of the risks of a decrease in the borrowing base under our revolving credit facility, see "Item 1A. Risk Factors—The borrowing base under our revolving credit facility may be reduced if commodity prices decline, which could hinder or prevent us from meeting our future capital needs."

Our commodity hedge position provides us with additional liquidity as it provides us with the relative certainty of receiving a significant portion of our future expected revenues from operations despite potential declines in the price of natural gas, NGLs, or oil. Our ability to make significant additional acquisitions for cash would require us to utilize borrowings on our revolving credit facility or obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. Our revolving credit facility is funded by a syndicate of 30 banks. We believe that the participants in the syndicate have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of our revolving credit facility. In addition to Antero's credit facility, Antero Midstream has a revolving credit facility that provides for lender commitments of $1.5 billion.

For the year ended December 31, 2016, our total consolidated capital expenditures were approximately $2.5 billion, including drilling and completion expenditures of $1.3 billion, leasehold additions of $153 million, acquisitions of $593 million, gathering and compression expenditures of $231 million, water handling and treatment expenditures of $188 million, and other capital expenditures of $3 million. Our consolidated capital budget for 2017 is $2.3 billion, and includes: $1.3 billion for drilling and completion, $200 million for core leasehold acreage additions and extensions, and $800 million for capital expenditures by Antero Midstream. We do not budget for acquisitions. Approximately 70% of the drilling and completion budget is allocated to the Marcellus Shale and the remaining 30% is allocated to the Utica Shale. During 2017, we plan to operate an average of four drilling rigs in the Marcellus Shale and three drilling rigs in the Utica Shale. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

We believe that funds from operating cash flows and available borrowings under our revolving credit facility, or capital market transactions, will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "—Debt Agreements and Contractual Obligations."

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2014, 2015, and 2016:

	Year Ended December 31,		
(in thousands)	2014	2015	2016
Net cash provided by operating activities	$ 998,263	1,015,812	1,241,256
Net cash used in investing activities	(4,089,650)	(2,298,159)	(2,395,138)
Net cash provided by financing activities	3,319,879	1,059,841	1,162,019
Net increase (decrease) in cash and cash equivalents	$ 228,492	(222,506)	8,137

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $998 million, $1.02 billion and $1.24 billion for the years ended December 31, 2014, 2015 and 2016, respectively. The increase in cash flows from operations from 2014 to 2015 and also from 2015 to 2016 was primarily the result of increases in total realized revenues from production and settled derivatives, net of increases in cash operating costs, interest expense, and changes in working capital levels.

Our operating cash flow is 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 determined primarily 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 Flow Used in Investing Activities

During the years ended December 31, 2014, 2015, and 2016, we used cash flows in investing activities of $4.1 billion, $2.3 billion, and $2.4 billion, respectively, as a result of our capital expenditures for drilling, development, acquisitions, and construction of midstream and water handling and treatment infrastructure. Our capital expenditures for drilling and completion activities decreased from $1.7 billion in 2015 to $1.3 billion in 2016 due to reductions in the number of contracted drilling rigs and completion crews. We undertook these actions in light of the low commodity price environment during 2016, as well as decreases in the required number of drilling rigs and completion crews due to efficiencies that we achieved for both activities. Our capital expenditures for additions to unproved property increased from $199 in 2015 to $612 million in 2016 due to the completion of several land acquisitions which totaled $459 million. Capital expenditures in 2016 were partially offset by proceeds of $172 million from our sale of producing and non-producing leasehold in Pennsylvania.

Our board of directors has approved a capital budget of $1.5 billion for 2017, which does not include the capital budget of approximately $800 million for Antero Midstream, our consolidated subsidiary. Our capital budget may be adjusted as business conditions warrant. 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 below our acceptable levels, or costs increase to levels above our acceptable levels, 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 flow. 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 flow, and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities in 2016 of $1.2 billion was primarily the result of (i) net proceeds of $1.0 billion from issuances of our common stock, (ii) proceeds from the issuance of senior notes by Antero Midstream of $650 million, (iii) proceeds from the issuance of senior notes by Antero of $600 million, (iv) proceeds from the sale of $178 million of Antero Midstream common units owned by Antero, (v) proceeds from the sale of $65 million of common units by Antero Midstream under its equity distribution agreement, net of (vi) repayments on our credit facilities of $677 million, (vii) $541 million for retirements of senior notes and payments for early redemption premiums, (viii) $75 million for distributions to noncontrolling interest owners in Antero Midstream, and (ix) other items totaling $51 million.

Net cash provided by financing activities in 2015 of $1.1 billion was primarily the result of (i) proceeds from the issuance of senior notes of $750 million, (ii) proceeds from the issuance of common stock of $538 million, (iii) proceeds from the issuance of common units in Antero Midstream of $241 million, net of (iv) repayments on our credit facilities of $403 million, (v) $34 million for distributions to noncontrolling interest owners in Antero Midstream, and (vi) other items totaling $32 million. The overall decrease in cash and cash equivalents of $223 million in 2015 is primarily due to capital expenditures by Antero Midstream using proceeds retained from its IPO in 2015. Antero Midstream had a cash balance of $230 million as of December 31, 2014 and $7 million as of December 31, 2015.

Net cash provided by financing activities in 2014 of $3.3 billion was primarily the result of (i) proceeds from the issuance of senior notes of $1.1 billion, (ii) net borrowings on our credit facilities of $1.4 billion, (iii) proceeds from the Antero Midstream IPO of $1.1 billion, net of (iv) $309 for retirements of senior notes and payments for early redemption premiums and deferred financing costs, and (v) other items totaling $3 million. The increase in cash and cash equivalents of $228 million in 2014 is primarily due to cash retained by Antero Midstream subsequent to its IPO. Antero Midstream had a cash balance of $230 million as of December 31, 2014.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility. We have a senior secured revolving bank 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 our assets and are subject to regular semiannual redeterminations. At December 31, 2016, the borrowing base was $4.75 billion and lender commitments were $4.0 billion. The next redetermination of the borrowing base is scheduled to occur in April 2017. At December 31, 2016, we had $440 million of borrowings and $710 million of letters of credit outstanding under the Credit Facility, with a weighted average interest rate of 2.44%. At December 31, 2015, we had $707 billion of borrowings and $702 million of letters of credit outstanding under the Credit Facility, with a weighted average interest rate of 2.32%. The Credit Facility matures on May 5, 2019.

Principal amounts borrowed on the Credit Facility are payable on the maturity dates 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 three months. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points, and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized. The amounts outstanding under the Credit Facility are secured by a first priority lien on substantially all of our natural gas, NGLs, and oil properties and associated assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly-owned subsidiaries. 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.

The Credit Facility also requires Antero and its restricted subsidiaries to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our consolidated current liabilities, of not less than 1.0 to 1.0 as of the end of each fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX to consolidated interest expense over the most recent four quarters, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2015 and December 31, 2016. The actual borrowing capacity available to us may be limited by the financial ratio covenants. At December 31, 2016, our current ratio was 6.54 to 1.0 (based on the $4.75 billion borrowing base as of December 31, 2016) and our interest coverage ratio was 6.29 to 1.0.

Midstream Credit Facility. Antero Midstream has a secured revolving credit facility (the “Midstream Facility”) among Antero Midstream, certain lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer, and swing line lender. The Midstream Facility provides for lender commitments of $1.5 billion and for a letter of credit sublimit of $150 million. As of December 31, 2016, Antero Midstream had a total outstanding balance under the Midstream Facility of $210 million, with a weighted average interest rate of 2.23%. As of December 31, 2015, Antero Midstream had a total outstanding balance under the Midstream Facility of $620 million, with a weighted average interest rate of 1.92%. The Midstream Facility matures on November 10, 2019.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly. Antero Midstream has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 225 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank’s reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 125 basis points, depending on the leverage ratio then in effect.

The Midstream Facility is secured by mortgages on substantially all of Antero Midstream’s and its restricted subsidiaries’ properties – primarily assets used in the provision of gathering and compression services and water handling and treatment services to Antero and third parties – and guarantees from its restricted subsidiaries. The Midstream Facility is not guaranteed by Antero. Interest is payable at a variable rate based on LIBOR or the prime rate based on Antero Midstream’s election at the time of borrowing. The Midstream Facility contains restrictive covenants that may limit Antero Midstream’s ability to, among other things:

- incur additional indebtedness;
- sell assets;

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

Borrowings under the Midstream Facility also require Antero Midstream to maintain the following financial ratios:

- an interest coverage ratio, which is the ratio of Antero Midstream's consolidated EBITDA to its consolidated current interest charges of at least 2.5 to 1.0 at the end of each fiscal quarter; provided that upon obtaining an investment grade rating, the borrower may elect not to be subject to such ratio;
- a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA of not more than 5.25 to 1.0, or, following the election of the borrower for two fiscal quarters after a material acquisition, 5.50 to 1.0; and
- a consolidated senior secured leverage ratio, which is the ratio of consolidated senior secured debt to consolidated EBITDA, of not more than 3.75 to 1.0.

Antero Midstream was in compliance with such covenants and ratios as of December 31, 2015 and December 31, 2016.

Antero Senior Notes. We have $1.0 billion of 5.375% senior notes outstanding, which are due November 1, 2021 (the "2021 notes"). 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 by our wholly-owned subsidiaries and certain of our 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 redemption prices ranging from 104.031% currently to 100.00% on or after November 1, 2019. If we undergo a change of control, we may be required to offer to purchase the 2021 notes from the holders at a price equal to 101% of the principal amount of the 2021 notes, plus accrued and unpaid interest.

We also have $1.1 billion of 5.125% senior notes outstanding, which are due December 1, 2022 (the "2022 notes"). 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 by our wholly-owned subsidiaries and certain of our 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 on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, we may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125%, plus accrued and unpaid interest. At any time prior to June 1, 2017, we may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a "make-whole" premium and accrued and unpaid interest. If we undergo a change of control, 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.

We also have $750 million of 5.625% senior notes outstanding, which are due June 1, 2023 (the "2023 notes"). 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 by our wholly-owned subsidiaries and certain of our 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 on or after June 1, 2018 at redemption prices ranging from 104.219% on or after June 1, 2018 to 100.00% on or after June 1, 2021. In addition, on or before June 1, 2018, we may redeem up to 35% of the aggregate principal amount of the 2023 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.625%, plus accrued and unpaid interest. At any time prior to June 1, 2018, we may also redeem the 2023 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2023 notes plus a "make-whole" premium and accrued and unpaid interest. If we undergo a change of control, 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.

We also have $600 million of 5.00% senior notes outstanding, which are due March 1, 2025 (the "2025 notes"). 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 by our wholly-owned subsidiaries and certain of our 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%, 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, 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, 2015 and December 31, 2016.

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 may be material.

Antero Midstream Senior Notes. Antero Midstream has $650 million of 5.375% senior notes outstanding, which are due September 15, 2024 (the "2024 Midstream notes"). The 2024 Midstream notes are unsecured and effectively subordinated to the Midstream Facility to the extent of the value of the collateral securing the Midstream Facility. The 2024 Midstream notes are guaranteed by Antero Midstream's wholly-owned subsidiaries – excluding the co-issuer of the notes, Midstream Finance Corp. – and certain of Antero Midstream's future restricted subsidiaries. Interest on the 2024 Midstream notes is payable on March 15 and September 15 of each year. Antero Midstream may redeem all or part of the 2024 Midstream notes at any time on or after September 15, 2019 at redemption prices ranging from 104.031% on or after September 15, 2019 to 100.00% on or after September 15, 2022. In addition, prior to September 15, 2019, Antero Midstream may redeem up to 35% of the aggregate principal amount of the 2024 Midstream notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375%, plus accrued and unpaid interest. At any time prior to September 15, 2019, Antero Midstream may also redeem the 2024 Midstream notes, in whole or in part, at a price equal to 100% of the principal amount of the 2024 Midstream notes plus a "make-whole" premium and accrued and unpaid interest. If Antero Midstream undergos a change of control, the holders of the 2024 Midstream notes will have the right to require Antero Midstream to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2024 Midstream notes, plus accrued and unpaid interest.

Treasury Management Facility. We have a stand-alone revolving note with a lender under the Credit Facility which 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 facility bear interest at the lender's prime rate plus 1.0%. The note matures on May 1, 2017. At December 31, 2015 and December 31, 2016, there were no outstanding borrowings under this facility.

Contractual Obligations. A summary of our contractual obligations as of December 31, 2016 is provided in the table below. Contractual obligations listed exclude minimum fees that we will pay to Antero Midstream, our consolidated subsidiary, under gathering, compression, and water services agreements.

	Year Ended December 31,						
(in millions)	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Antero Resources Credit Facility(1)	$ —	—	440	—	—	—	440
Antero Midstream Facility(1)	—	—	210	—	—	—	210
Antero Resources senior notes—principal(2)	—	—	—	—	1,000	2,450	3,450
Antero Resources senior notes—interest(2)	173	182	182	182	156	240	1,115
Antero Midstream senior notes—principal(2)	—	—	—	—	—	650	650
Antero Midstream senior notes—interest(2)	35	35	35	35	35	105	280
Drilling rig and completion service commitments(3)	109	105	64	—	—	—	278
Firm transportation (4)	626	935	1,086	1,105	1,084	10,551	15,387
Processing, gathering, and compression services (5)	373	289	243	241	223	1,000	2,369
Office and equipment leases	14	13	10	8	8	25	78
Asset retirement obligations(6)	—	—	—	—	—	33	33
Total	$ 1,330	1,559	2,270	1,571	2,506	15,054	24,290

(1) Includes outstanding principal amounts at December 31, 2016. This table does not include future commitment fees, interest expense or other fees on our Credit Facility or the Midstream 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.

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

(3) Includes contracts for the services of drilling rigs and hydraulic fracturing fleets, which expire at various dates from February 2017 through February 2020. 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 interest.

(4) Includes firm transportation agreements with various pipelines in order to facilitate the delivery of 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 interest.

(5) Contractual commitments for processing, gathering, and compression services agreements represent minimum commitments under long-term agreements. Includes Antero Midstream's commitments for the construction of its advanced waste water treatment complex. 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 interest. The table does not include intracompany commitments.

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

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. Our more significant accounting policies and estimates include the successful efforts method of accounting for our production activities, estimates of natural gas, NGLS, and oil reserve quantities and standardized measures of future cash flows, and impairment of proved properties. We provide an expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in the preparation of our consolidated financial statements. 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 crude 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, 2014, 2015, and 2016. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units of production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties with significant acquisition costs are assessed for impairment on a property by property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on, or otherwise attributed to, the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties for leases which have expired, or are expected to expire, was $15.2 million, $104.3 million, and $162.9 million for the years ended December 31, 2014, 2015, and 2016, 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 will 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.

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), we would estimate the fair value of our properties and record an impairment charge for any excess of the carrying amount of the properties over the estimated fair value of the properties. Given the rapid decline in the market prices of natural gas, NGLs, and oil that occurred during the fourth quarter of 2014 and lower price environment that continued through 2016, at the end of each quarter during 2016 we compared estimated undiscounted future net cash flows using futures pricing for our Utica and Marcellus Basin properties to the carrying value of those properties. Estimated undiscounted future net cash flows have exceeded the carrying value at the end of each quarter, including at December 31, 2016, and thus, no further evaluation of the fair value of the properties for impairment is required under GAAP. As a result, we have not recorded any impairment expenses associated with our Utica and Marcellus Basin proved properties during the year ended December 31, 2016. Additionally, we did not record any impairment expenses for proved properties during the years ended December 31, 2014 and 2015.

Based on current future commodity prices, we currently do not anticipate having to record any impairment charge for our proved properties in the near future. We estimate that if strip prices were to decline by approximately $0.75 per Mcf for gas and by approximately $7.50 per barrel for oil from future pricing levels at December 31, 2016, 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 $0.75 per Mcf and $7.50 per barrel of oil from year end 2016 levels before further evaluation of those properties would be required in order to determine if an impairment charge would be necessary under GAAP. We are unable, however, to predict commodity prices with any greater precision than the futures market.

Income Taxes

We are subject to state and federal income taxes, but are currently not in a tax paying position for regular federal income taxes, primarily due to the differences in the tax and financial statement treatment of oil and gas properties, and the deferral of unsettled commodity hedge gains for tax purposes until they are settled in an exchange of cash. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income, primarily from derivatives, oil and gas properties, and net operating loss carryforwards. We have generated net operating loss carryforwards that expire at various dates from 2017 through 2036, 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, 2016, we have recognized a valuation allowance of $16 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

On May 28, 2014, the Financial Accounting Standards Board ("FASB") issued 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 will replace most existing revenue recognition guidance in GAAP when it becomes effective. Additionally, on May 3, 2016, the FASB issued ASU No. 2016-11, which rescinds SEC accounting guidance regarding the use of the entitlements method for recognition of natural gas revenues. The new standards become effective for the Company on January 1, 2018. Early application is not permitted. The standards permit the use of either the retrospective or cumulative effect transition method. The Company has not yet selected a transition method. While the Company is still evaluating the effect that ASU 2014-09 and ASU No. 2016-11 will have on its consolidated financial statements and related disclosures, currently, we do not believe that there will be a significant effect on our consolidated financial statements upon adoption of these standards. To the extent applicable, upon adoption, we may be required to comply with expanded disclosure requirements, including the disaggregation of revenues to depict the nature and uncertainty of types of revenues, contract assets and liabilities, current period revenues previously recorded as a liability, performance obligations, significant judgments and estimates affecting the amount and timing of revenue recognition, determination of transaction prices, and allocation of the transaction price to performance obligations. We continue to monitor relevant industry guidance regarding implementation of ASU 2014-09 and ASU 2016-11 and adjust our implementation strategies as necessary. We believe that adoption of the standards will not impact our operational strategies, growth prospects, or cash flows.

On February 25, 2016, the FASB issued ASU No. 2016-02, Leases, which requires all leasing arrangements to be presented in the balance sheet as liabilities along with a corresponding asset. The ASU will replace most existing leases guidance in GAAP when it becomes effective. The new standard becomes effective for the Company on January 1, 2019. Although early application is permitted, the Company does not plan to early adopt the ASU. The standard requires the use of the modified retrospective transition method. The Company is evaluating the effect that ASU 2016-02 will have on its consolidated financial statements and related disclosures. Currently, the Company is evaluating the standard's applicability to our various contractual arrangements. We believe that adoption of the standard will result in increases to our assets and liabilities on our consolidated balance sheet, as well as changes to the presentation of certain operating expenses on our consolidated statement of operations; however, we have not yet determined the extent of the adjustments that will be required upon implementation of the standard. We continue to monitor relevant industry guidance regarding implementation of ASU 2016-02 and adjust our implementation strategies as necessary. We believe that adoption of the standard will not impact our operational strategies, growth prospects, or cash flows.

On June 16, 2016, the FASB issued ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires an entity to measure its financial assets at the net amount expected to be collected. The ASU will replace most existing guidance in GAAP regarding the valuation of financial assets when it becomes effective. The new standard becomes effective for the Company on January 1, 2020. The Company does not believe that this standard will have a material impact on its ongoing financial reporting upon adoption.

On August 26, 2016, the FASB issued ASU No. 2016-15, *Classification of Certain Cash Receipts and Cash Payments*, which removes diversity in practice in how certain cash receipts and payments are presented and classified in the statement of cash flows, including the presentation of debt extinguishment costs and the presentation of distributions received from equity method investees. The new standard becomes effective for the Company on January 1, 2018. The Company does not believe that this standard will have a material impact on its ongoing financial reporting upon adoption.

As of December 31, 2016, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rig and hydraulic fracturing services, firm transportation, gas processing, gathering, and compression services. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for commitments under operating leases, drilling rig and hydraulic fracturing service agreements, firm transportation, gas processing, gathering, and compression service 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. The 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. All of our market risk sensitive derivative instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas, NGLs, and oil production. Realized pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production and the prevailing worldwide price for crude oil. Pricing for natural gas, NGLs, and oil production has, historically, been volatile and unpredictable, and we expect this volatility to continue in the future. The prices we receive for 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 derivative instruments to receive fixed prices for a portion of our natural gas, NGLs, and oil production when management believes that favorable future prices can be secured. At December 31, 2016, the majority of our natural gas hedges were fixed price swaps at NYMEX pricing.

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, cashless price 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. Under the commodity price swap contracts, the counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference. The Company was not party to any collars as of, or during the year ended, December 31, 2016.

At December 31, 2016, we had in place natural gas, NGLs, and oil swaps covering portions of our projected production from 2017 through 2022. Our commodity hedge position as of December 31, 2016 is summarized in note 11 to our consolidated financial statements included elsewhere herein. The Credit Facility allows us to hedge up to 75% of our projected production for the next five years, and 65% of our subsequent estimated proved reserves through December 31, 2023. Based on our production and our fixed price swap contracts which settled during the year ended December 31, 2016, our revenues would have decreased by approximately $9.0 million for each $0.10 decrease per MMBtu in natural gas prices and $1.00 decrease per Bbl in oil and NGLs prices.

All derivative instruments, other than those that meet the normal purchase and normal sale 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 (both settled derivatives and derivative positions which remain open) within our 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. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are only impacted when the associated derivative instrument contracts are settled by making or receiving payments to or from the counterparty. At December 31, 2016, the estimated fair value of our commodity derivative instruments was a net asset of $1.6 billion, comprised of current and noncurrent assets and liabilities. At December 31, 2015, the estimated fair value of our commodity derivative instruments was a net asset of $3.1 billion, comprised of current and noncurrent assets.

By removing price volatility from a portion of our expected production through December 2022, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those periods. While mitigating 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 commodity derivative contracts ($1.8 billion at December 31, 2016), the sale of our oil and gas production ($224 million at December 31, 2016) which we market to energy companies, end users and refineries, the marketing of our excess firm transportation capacity ($38 million at December 31, 2016), and joint interest receivables ($15 million at December 31, 2016).

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 the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions which management deems to be competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have commodity hedges in place with fifteen different counterparties, all of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately $1.6 billion at December 31, 2016 includes the following values by bank counterparty: Morgan Stanley—$551 million; Barclays—$392 million; JP Morgan—$306 million; Wells Fargo—$159 million; Scotiabank—$136 million; Canadian Imperial Bank of Commerce—$58 million; Toronto Dominion Bank—$32 million; Fifth Third Bank—$12 million; Bank of Montreal—$10 million; and Capital One—$2 million. The credit ratings of certain of these banks were downgraded in recent years because of their exposure to the sovereign debt crisis in Europe or various other factors. 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, 2016 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, 2016, 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.

Joint interest receivables arise from billing entities who own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we drill. We have minimal control over deciding who participates in our wells.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility and the Midstream Facility of our consolidated subsidiary, Antero Midstream. Each of these credit facilities has a floating interest rate. The average annual interest rate incurred on this indebtedness during the year ended December 31, 2016 was approximately 2.14%. A 1.0% increase in each of the applicable average interest rates for the year ended December 31, 2016 would have resulted in an estimated $10.7 million increase in interest expense.

Item 8. Financial Statements and Supplementary Data

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

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

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report. Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. 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, 2016.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2016 that has materially affected, or is 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, 2016.

The effectiveness of our internal control over financial reporting as of December 31, 2016 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, 2016, as stated in their reports which appear beginning on page F-2 in this report.

Item 9B. Other Information

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

Pursuant to Section 13(r) of the Securities Exchange Act of 1934, we, Antero Resources Corporation, may be required to disclose in our annual and quarterly reports to the Securities and Exchange Commission (the "SEC"), whether we or any of our "affiliates" knowingly engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by U.S. economic sanctions. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Because the SEC defines the term “affiliate” broadly, it includes any entity under common “control” with us (and the term “control” is also construed broadly by the SEC).

The description of the activities below has been provided to us by Warburg Pincus LLC (“WP”), affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and/or are members of our board of directors, (ii) beneficially own more than 10% of the equity interests of, and have the right to designate members of the board of directors of Santander Asset Management Investment Holdings Limited (“SAMIH”). SAMIH may therefore be deemed to be under common “control” with us; however, this statement is not meant to be an admission that common control exists.

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

We understand that one or more SEC-reporting affiliates of SAMIH intends to disclose in its next annual or quarterly SEC report that:

(a) Santander UK plc (“Santander UK”) holds two savings accounts and one current account for two customers resident in the United Kingdom (“UK”) who are currently designated by the United States (“US”) under the Specially Designated Global Terrorist (“SDGT”) sanctions program. Revenues and profits generated by Santander UK on these accounts in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA.

(b) Santander UK held a savings account for a customer resident in the UK who is currently designated by the US under the SDGT sanctions program. The savings account was closed on July 26, 2016. Revenue generated by Santander UK on this account in the year ended December 31, 2016 was negligible relative to the overall revenues of Banco Santander SA.

(c) Santander UK held a current account for a customer resident in the UK who is currently designated by the US under the SDGT sanctions program. The current account was closed on December 22, 2016. Revenue generated by Santander UK on this account in the year ended December 31, 2016 was negligible relative to the overall revenues and profits of Banco Santander SA.

(d) Santander UK holds two frozen current accounts for two UK nationals who are designated by the US under the SDGT sanctions program. The accounts held by each customer have been frozen since their designation and have remained frozen through the year ended December 31, 2016. The accounts are in arrears (£1,844.73 in debit combined) and are currently being managed by Santander UK Collections & Recoveries department. Revenues and profits generated by Santander UK on these accounts in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA.

(e) In addition, during the year ended December 31, 2016, Santander UK had an OFAC match on a power of attorney account. A party listed on the account is currently designated by the US under the SDGT sanctions program and the Iranian Financial Sanctions Regulations (“IFSR”). The power of attorney was removed from the account on July 29, 2016. During the year ended December 31, 2016, related revenues and profits generated by Santander UK were negligible relative to the overall revenues and profits of Banco Santander SA.

(f) An Iranian national, resident in the UK, who is currently designated by the US under the IFSR and the Weapons of Mass Destruction Proliferators Sanctions Regulations, held a mortgage with Santander UK that was issued prior to such designation. The mortgage account was redeemed and closed on April 13, 2016. No further drawdown has been made (or would be allowed) under this mortgage although Santander UK continued to receive repayment instalments prior to redemption. Revenues generated by Santander UK on this account in the year ended December 31, 2016 were negligible relative to the overall revenues of Banco Santander SA. The same Iranian national also held two investment accounts with Santander ISA Managers Limited. The funds within both accounts were invested in the same portfolio fund. The accounts remained frozen until the investments were closed on May 12, 2016 and bank checks issued to the customer. Revenues generated by Santander UK on these accounts in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA.

(g) In addition, during the year ended December 31, 2016, Santander UK held a basic current account for an Iranian national, resident in the UK, previously designated under the Iranian Transactions and Sanctions Regulations. The account was closed in September 2016. Revenues generated by Santander UK on this account in the year ended December 31, 2016 were negligible relative to the overall revenues and profits of Banco Santander SA.

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 2017 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 28, 2017:

Name	Age	Title
Paul M. Rady	63	Chairman of the Board, Director and Chief Executive Officer
Glen C. Warren, Jr.	61	President, Director, Chief Financial Officer and Secretary
Michael N. Kennedy	42	Senior Vice President—Finance
Kevin J. Kilstrom	62	Senior Vice President—Production
Ward D. McNeilly	66	Senior Vice President—Reserves, Planning and Midstream
Alvyn A. Schopp	58	Chief Administrative Officer, Regional Senior Vice President and Treasurer
Robert J. Clark	72	Director
Richard W. Connor	67	Director
Benjamin A. Hardesty	67	Director
Peter R. Kagan	48	Director
W. Howard Keenan, Jr.	66	Director
James R. Levy	40	Director

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

Paul M. Rady has served as Chief Executive Officer and Chairman of the Board of Directors since May 2004. Mr. Rady also served as Chief Executive Officer and Chairman of the Board of Directors of our predecessor company, Antero Resources Corporation, from its founding in 2002 until its sale to XTO Energy, Inc. in April 2005. Mr. Rady also serves as Chairman of the Board of Directors of the general partner of Antero Midstream Partners LP. Prior to Antero Resources Corporation, 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 holds a B.A. in Geology from Western State College of Colorado and M.Sc. in Geology from Western Washington University.

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

Glen C. Warren, Jr. has served as President, Chief Financial Officer and Secretary and as a director since May 2004. Mr. Warren also served as President and Chief Financial Officer and as a director of our predecessor company, Antero Resources Corporation, from its founding in 2002 until its sale to XTO Energy, Inc. in April 2005. Mr. Warren also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. Prior to Antero Resources Corporation, 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 & Co. Inc. and Kidder, Peabody & Co. Mr. Warren began his career as a landman in the Gulf Coast region with Amoco, where he spent six years. Mr. Warren holds a B.A. from the University of Mississippi, a J.D. from the University of Mississippi School of Law and an M.B.A. from the Anderson School of Management at U.C.L.A.

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

Michael N. Kennedy has served as Senior Vice President of Finance since January 2016, prior to which he served as Vice President of Finance beginning in August 2013. Mr. Kennedy was Executive Vice President and Chief Financial Officer of Forest Oil Corporation ("Forest") from 2009 to 2013. From 2001 until 2009, Mr. Kennedy held various financial positions of increasing responsibility within Forest. From 1996 to 2001, Mr. Kennedy was an auditor with Arthur Andersen LLP focusing on the Natural Resources industry. Mr. Kennedy holds a B.S. in Accounting from the University of Colorado at Boulder.

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

Ward D. McNeilly serves as Senior Vice President of Reserves, Planning & Midstream, and has been with the Company since October 2010. Mr. McNeilly has 37 years of experience in oil and gas asset management, operations, and reservoir management. From 2007 to October 2010, Mr. McNeilly was BHP Billiton's Gulf of Mexico Operations Manager. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. Mr. McNeilly served in a number of different domestic and international positions with Amoco from 1979 to 1996. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

Alvyn A. Schopp has served as Chief Administrative Officer, Regional Senior Vice President, and Treasurer since January 2016. Mr. Schopp also served as Chief Administrative Officer, Regional Vice President, and Treasurer from September 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 Vice President of Accounting and Administration and Treasurer of our predecessor company, Antero Resources Corporation, from January 2005 until its ultimate sale to XTO Energy, Inc. in April 2005. 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, most recently as a Senior Manager focusing on the energy and mining industries. Mr. Schopp holds a B.B.A. from Drake University.

Robert J. Clark has served as a director, member of the audit committee and Chairman of the compensation committee since our initial public offering in October 2013. Mr. Clark has been Chairman and Chief Executive Officer of 3 Bear Energy, LLC, a midstream energy company with operations in the Rocky Mountains, since its formation in March 2013. Prior to the formation of 3 Bear Energy LLC, Mr. Clark formed, operated and subsequently sold Bear Tracker Energy in February 2013 (to Summit Midstream Partners, LP), a portion of Bear Cub Energy in April 2007 (to Regency Energy Partners, L.P.) and the remaining portion in December 2008 (to GeoPetro Resources Company) and Bear Paw Energy in 2001 (to ONEOK Partners, L.P., formerly Northern Border Partners, L.P.). Mr. Clark received his Bachelor of Science degree from Bradley University and his Master's Degree in Business Administration from Northern Illinois University. Mr. Clark is a member of the board of trustees of Bradley University and serves on the boards of trustees for both the Children's Hospital Colorado Foundation and Judi's House, a Denver charity for grieving children and families.

Mr. Clark has significant experience with energy companies, with over 45 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.

Richard W. Connor has served as a director and chairman of our audit committee since September 1, 2013. Prior to his retirement in September 2009, Mr. Connor was an audit partner with KPMG LLP, or KPMG, where he principally served publicly traded clients in the energy, mining, telecommunications, and media industries for 38 years. Mr. Connor was elected to the partnership in 1980 and was appointed to KPMG's SEC Reviewing Partners Committee in 1987 where he served until his retirement. From 1996 to September 2008, he served as the Managing Partner of KPMG's Denver office. Mr. Connor earned his B.S. degree in accounting from the University of Colorado. Mr. Connor is a member of the Board of Directors of Zayo Group LLC, a provider of bandwidth infrastructure and colocation services. Mr. Connor is also a director of Centerra Gold, Inc. (TSX: CG.T), a Toronto-based gold mining company listed on the Toronto Stock Exchange. Mr. Connor also serves as a director and chairman of the audit committee of the general partner of Antero Midstream Partners LP.

Mr. Connor has experience in technical accounting and auditing matters, knowledge of SEC filing requirements and experience with a variety of energy clients. We believe his background and skill set make Mr. Connor well-suited to serve as a member of our board of directors and as chairman of our audit committee.

Benjamin A. Hardesty has served as a director, chairman of our nominating and governance committees, and member of our compensation committee since our initial public offering in October 2013. He has also served as a member of our audit committee since September 2014. 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. Mr. Hardesty is a member of the Board of Directors of KLX, Inc. (NASDAQ: KLXI). 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 recent sale to B/E Aerospace. 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 serve as vice president–operations of Development Drilling Corp. Mr. Hardesty received his Bachelor of Science degree from West Virginia University and Master of Science–Management degree from The George Washington University. Mr. Hardesty served as an active duty officer in the United States Army Security Agency. 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 and Natural Gas Engineering Department of the College of Engineering and Mineral Resources at West Virginia University.

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

Peter R. Kagan has served as a director since 2004. Mr. Kagan has been with Warburg Pincus since 1997 where he leads the firm's investment activities in energy and natural resources. He is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. He is also a member of Warburg Pincus LLC's Executive Management Group. Mr. Kagan received a B.A. degree cum laude from Harvard College and J.D. and M.B.A. degrees with honors from the University of Chicago. Prior to joining Warburg Pincus, he worked in investment banking at Salomon Brothers in both New York and Hong Kong. Mr. Kagan currently also serves on the boards of directors of the following public companies: Laredo Petroleum, MEG Energy Corp. and Targa Resources Corp., as well as the boards of several private companies. Mr. Kagan also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. In addition, he is a director of Resources for the Future and a trustee of Milton Academy.

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

W. Howard Keenan, Jr. has served as a director since 2004. 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. Mr. Keenan also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. 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 in the last five years as a director of the following public companies: Concho Resources; Geomet Inc.; and Ramaco Resources, as well as multiple Yorktown Partners portfolio companies. Mr. Keenan holds an B.A. degree cum laude from Harvard College and an M.B.A. degree from Harvard University.

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

James R. Levy has served as a director and member of our compensation committee since our initial public offering in October 2013. Mr. Levy joined Warburg Pincus in 2006 and focuses on investments in the energy industry. Mr. Levy is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. Prior to joining Warburg Pincus, Mr. Levy worked as a private equity investor at Kohlberg & Company and in M&A advisory at Wasserstein Perella & Co. Mr. Levy currently serves on the board of directors of Laredo Petroleum as well as the board of directors of several private companies. In addition, he is a trustee of Prep for Prep. Mr. Levy received a Bachelor of Arts degree from Yale University.

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

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 2017 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 2017 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 2017 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 2017 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 report beginning on page F-1.

(a)(3) Exhibits.

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

Exhibit Number	Description of Exhibit
2.1	Contribution, Conveyance and Assumption Agreement, dated as of September 17, 2015, by and among Antero Resources Corporation, Antero Midstream Partners LP and Antero Treatment LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 18, 2015).
2.2	Purchase and Sale Agreement, dated June 1, 2012, between Antero Resources Corporation and Vanguard Permian, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 5, 2012)
2.3	Purchase and Sale Agreement by and among Antero Resources Piceance LLC, Antero Resources Pipeline LLC and Ursa Resources Group II LLC, dated as of November 1, 2012 (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 6, 2012).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	Amended and Restated Bylaws of Antero Resources Corporation (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.1	Indenture related to the 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
4.2	Form of 5.375% Senior Note due 2021 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
4.3	First Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.4	Second Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
4.5	Registration Rights Agreement related to the 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).
4.6	Registration Rights Agreement, dated as of October 16, 2013, by and among Antero Resources Corporation and the owners of the membership interests in Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.7	Indenture related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.8	Form of 5.125% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.9	First Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of November 24, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Antero Resource Corporation's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on November 26, 2014).

4.1	Second Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of January 21, 2015, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.6 to Registration Statement Report on Form S-4 (Commission File No. 333-200605) filed on January 22, 2015).
4.11	Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.12	Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of September 18, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2014).
4.13	Indenture related to the 5.625% Senior Notes due 2023, dated as of March 17, 2015, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on March 18, 2015).
4.14	Form of 5.625% Senior Note due 2023 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on March 18, 2015).
4.15	Registration Rights Agreement related to the 5.625% Senior Notes due 2023, dated as of March 17, 2015, by and among Antero Resources Corporation, the subsidiary guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on March 18, 2015).
4.16	Indenture related to the 5.0% Senior Notes due 2025, dated as of December 21, 2016, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on December 29, 2016).
4.17	Form of 5.0% Senior Note due 2025 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 29, 2016).
4.18	Registration Rights Agreement related to the 5.0% Senior Notes due 2025, dated as of December 21, 2016, by and among Antero Resources Corporation, the subsidiary guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on December 29, 2016).
4.19	Registration Rights Agreement, dated as of October 7, 2016, by and among Antero Resources Corporation and the Purchaser named therein (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016.
10.1	Contribution Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.2	Amended and Restated Contribution Agreement, dated as of November 10, 2014, by and between Antero Resources Corporation and Antero Midstream Partners LP (incorporated by reference to Exhibit 10.1 to Antero Midstream Partners LP's Current Report on Form 8-K (Commission File No. 00136719) filed on November 17, 2014).
10.3	Gathering and Compression Agreement, dated as of November 10, 2014, by and between Antero Resources Corporation and Antero Midstream LLC (incorporated by reference to Exhibit 10.2 to Antero Midstream Partners LP's Current Report on Form 8-K (Commission File No. 00136719) filed on November 17, 2014).
10.4	Amended and Restated Right of First Offer Agreement, dated as of February 6, 2017, by and between Antero Resources Corporation and Antero Midstream LLC (incorporated by reference to Exhibit 10.1 to Antero Midstream Partners LP's Current Report on Form 8-K (Commission File No. 00136719) filed on February 6, 2017).
10.5	License Agreement, dated as of November 10, 2014, by and between Antero Resources Corporation and Antero Midstream Partners LP (incorporated by reference to Exhibit 10.4 to Antero Midstream Partners LP's Current Report on Form 8-K (Commission File No. 00136719) filed on November 17, 2014).
10.6	Secondment Agreement, dated as of September 23, 2015, by and between Antero Midstream Partners LP, Antero Resources Midstream Management LLC, Antero Midstream LLC, Antero Water LLC, Antero Treatment LLC and Antero Resources Corporation (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2015).
10.7	Amended and Restated Services Agreement, dated as of September 23, 2015, by and among Antero Midstream Partners LP, Antero Resources Midstream Management LLC and Antero Resources Corporation (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2015).

10.8†	Water Services Agreement, dated as of September 23, 2015, by and between Antero Resources Corporation and Antero Water LLC (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2015).
10.9	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.15 to Amendment No. 3 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on September 24, 2013).
10.10	Agreement and Plan of Merger, dated as of October 1, 2013, by and among Antero Resources Corporation, Antero Resources LLC and Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 11, 2013).
10.11	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).
10.12	Limited Liability Company Agreement of Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.13	Fourth Amended And Restated Credit Agreement dated as of November 4, 2010 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, Bank of Scotland Plc, Union Bank, N.A., Credit Agricole Corporate and Investment Bank, BNP Paribas and Deutsche Bank Trust Company Americas, as Co-Documentation Agents and J.P. Morgan Securities LLC and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 8, 2010).
10.14	First Amendment to the Fourth Amended And Restated Credit Agreement, dated as of May 12, 2011, among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on May 16, 2011).
10.15	Second Amendment to Fourth Amended And Restated Credit Agreement dated as of July 8, 2011 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 11, 2011).
10.16	Third Amendment to Fourth Amended And Restated Credit Agreement dated as of October 26, 2011 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 28, 2011).
10.17	Fourth Amendment to Fourth Amended And Restated Credit Agreement dated as of May 4, 2012 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on May 7, 2012).
10.18	Fifth Amendment to Fourth Amended and Restated Credit Agreement dated as of October 25, 2012 among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party hereto, and JP Morgan Chase Bank, N.A. as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 26, 2012).
10.19	Sixth Amendment to Fourth Amended and Restated Credit Agreement dated as of May 9, 2013 by and among Antero Resources Appalachian Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to increase the borrowing base and lender commitments and amend the current ratio covenant under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on May 13, 2013).
10.20	Seventh Amendment to Fourth Amended and Restated Credit Agreement dated as of June 27, 2013 by and among Antero Resources Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to increase the borrowing base and lender commitments and amend the current ratio covenant under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on August 9, 2013).

10.21 Eighth Amendment to Fourth Amended and Restated Credit Agreement dated as of August 29, 2013 by and among Antero Resources Corporation and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.23 to Registration Statement on Form S-1/A (Commission File No. 333-189284) filed on August 30, 2013).

10.22 Ninth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 21, 2013, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2013).

10.23 Tenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).

10.24 Eleventh Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).

10.25 Twelfth Amendment to Fourth Amended and Restated Credit Agreement, dated as of July 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on July 31, 2014).

10.26 Thirteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as September 8, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 10, 2014).

10.27 Fourteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as October 16, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2014).

10.28 Fifteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as November 10, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).

10.29 Sixteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 17, 2015, by and among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on February 17, 2015).

10.30 Seventeenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 26, 2015, by and among Antero Resources Corporation, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 28, 2015).

10.31 Eighteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of January 12, 2016, by and among Antero Resources Corporation, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on January 15, 2016).

10.32 Nineteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of April 8, 2016, by and among Antero Resources Corporation, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on April 27, 2016).

10.33 Twentieth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 24, 2016, by and among Antero Resources Corporation, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).

10.34 Credit Agreement, dated as of February 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).

10.35	First Amendment to Credit Agreement, dated as of May 5, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
10.36	Second Amendment to Credit Agreement, dated as of July 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on July 31, 2014).
10.37	Third Amendment to Credit Agreement, dated as of October 16, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2014).
10.38	Fourth Amendment to Credit Agreement, dated as of November 10, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.7 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
10.39	Fifth Amendment to Credit Agreement, dated as of November 7, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.6 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
10.40	Sixth Amendment to Credit Agreement, dated as of February 17, 2015, by and among Antero Water LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on February 17, 2015).
10.41	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 25, 2015).
10.42	Form of Bonus Stock Grant Notice and Bonus Stock Agreement (Form for Non-Employee Directors) under the Antero Resources Corporation Long-Term Incentive Plan.
10. 43	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 Current Report on Form 8-K (Commission File No. 001-36120) filed on February 12, 2016).
10.44	Global Amendment to Grant Notices and Award Agreements Under the Antero Resources Corporation Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).
10.45	Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Antero Midstream Partners’ Registration Statement on Form S-8 (Commission File No. 001-36719) filed on November 12, 2014).
10.46	Form of Phantom Unit Grant Notice and Phantom Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to Antero Midstream Partners’ Registration Statement on Form S-8 (Commission File No. 001-36719) filed on November 12, 2014).
10.47	Form of Restricted Unit Grant Notice and Restricted Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to Antero Midstream Partners’ Registration Statement on Form S-8 (Commission File No. 001-36719) filed on November 12, 2014).
10.48	Form of Bonus Unit Grant Notice and Bonus Unit Agreement (Form for Non-Employee Directors) under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 10.12 to Antero Midstream Partners’ Annual Report on Form 10-K (Commission File No. 001-36719) filed on February 24, 2016).
10.49	Letter Agreement dated June 29, 2012 by and among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation, Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 5, 2012).
10.50	Letter Agreement dated November 19, 2012 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 10, 2012).

10.51	Letter Agreement dated December 7, 2012 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 10, 2012).
10.52	Letter Agreement dated February 4, 2013 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on February 4, 2013).
10.53	Common Stock Subscription Agreement, dated as of October 3, 2016, by and between Antero Resources Corporation and the Purchaser named on Schedule A thereto (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on October 26, 2016).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
21.1*	Subsidiaries of Antero Resources Corporation.
23.1*	Consent of KPMG, LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
99.1*	Report of DeGolyer and MacNaughton, dated as of January 23, 2017, for proved reserves as of December 31, 2016.
99.2	Report of DeGolyer and MacNaughton, dated as of January 19, 2016, for proved reserves as of December 31, 2015 (incorporated by reference to Exhibit 99.1 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 25, 2016).
99.3	Report of DeGolyer and MacNaughton, dated as of January 19, 2015, for proved reserves as of December 31, 2014 (incorporated by reference to Exhibit 99.1 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2015).
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Consolidated Statements of Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.

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

†Portions of this exhibit have been omitted pursuant to a request for confidential treatment.

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 28, 2017

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 28, 2017
/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr.	President, Director, Chief Financial Officer and Secretary (principal financial officer)	February 28, 2017
/s/ K. PHIL YOO K. Phil Yoo	Vice President—Accounting, Chief Accounting Officer and Corporate Controller (principal accounting officer)	February 28, 2017
/s/ ROBERT J. CLARK Robert J. Clark	Director	February 28, 2017
/s/ RICHARD W. CONNOR Richard W. Connor	Director	February 28, 2017
/s/ BENJAMIN A. HARDESTY Benjamin A. Hardesty	Director	February 28, 2017
/s/ PETER R. KAGAN Peter R. Kagan	Director	February 28, 2017
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 28, 2017
/s/ JAMES R. LEVY James R. Levy	Director	February 28, 2017

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Antero Resources Corporation:

We have audited the accompanying consolidated balance sheets of Antero Resources Corporation and subsidiaries (the Company) as of December 31, 2015 and 2016, and 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, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Antero Resources Corporation and subsidiaries as of December 31, 2015 and 2016, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Antero Resources Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2017 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Denver, Colorado
February 28, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Antero Resources Corporation:

We have audited Antero Resources Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Antero Resources Corporation's management is responsible 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 Antero Resources Corporation's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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.

In our opinion, Antero Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Antero Resources Corporation and subsidiaries as of December 31, 2015 and 2016, and 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, 2016, and our report dated February 28, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Denver, Colorado
February 28, 2017

ANTERO RESOURCES CORPORATION

Consolidated Balance Sheets

December 31, 2015 and 2016

(In thousands, except per share amounts)

	2015	2016
Assets		
Current assets:		
Cash and cash equivalents	$ 23,473	31,610
Accounts receivable, net of allowance for doubtful accounts of $1,195 in 2015 and 2016	79,404	29,682
Accrued revenue	128,242	261,960
Derivative instruments	1,009,030	73,022
Other current assets	8,087	6,313
Total current assets	1,248,236	402,587
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	1,996,081	2,331,173
Proved properties	8,211,106	9,549,671
Water handling and treatment systems	565,616	744,682
Gathering systems and facilities	1,502,396	1,723,768
Other property and equipment	46,415	41,231
	12,321,614	14,390,525
Less accumulated depletion, depreciation, and amortization	(1,589,372)	(2,363,778)
Property and equipment, net	10,732,242	12,026,747
Derivative instruments	2,108,450	1,731,063
Other assets	26,565	95,153
Total assets	$ 14,115,493	14,255,550
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 69,911	38,627
Accrued liabilities	488,325	393,803
Revenue distributions payable	129,949	163,989
Derivative instruments	—	203,635
Other current liabilities	19,085	17,334
Total current liabilities	707,270	817,388
Long-term liabilities:		
Long-term debt	4,668,782	4,703,973
Deferred income tax liability	1,370,686	950,217
Derivative instruments	—	234
Other liabilities	82,077	55,160
Total liabilities	6,828,815	6,526,972
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; issued and outstanding 277,036 shares and 314,877 shares, respectively	2,770	3,149
Additional paid-in capital	4,122,811	5,299,481
Accumulated earnings	1,808,811	959,995
Total stockholders' equity	5,934,392	6,262,625
Noncontrolling interest in consolidated subsidiary	1,352,286	1,465,953
Total equity	7,286,678	7,728,578
Total liabilities and equity	$ 14,115,493	14,255,550

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income (Loss)

Years Ended December 31, 2014, 2015, and 2016

(In thousands, except per share amounts)

	2014	2015	2016
Revenue and other:			
Natural gas sales	$ 1,301,349	1,039,892	1,260,750
Natural gas liquids sales	328,323	264,483	432,992
Oil sales	107,080	70,753	61,319
Gathering, compression, and water handling and treatment	22,075	22,000	12,961
Marketing	53,604	176,229	393,049
Commodity derivative fair value gains (losses)	868,201	2,381,501	(514,181)
Gain on sale of assets	40,000	—	97,635
Total revenue and other	2,720,632	3,954,858	1,744,525
Operating expenses:			
Lease operating	29,341	36,011	50,090
Gathering, compression, processing, and transportation	461,413	659,361	882,838
Production and ad valorem taxes	87,918	78,325	66,588
Marketing	103,435	299,062	499,343
Exploration	27,893	3,846	6,862
Impairment of unproved properties	15,198	104,321	162,935
Depletion, depreciation, and amortization	477,896	709,763	809,873
Accretion of asset retirement obligations	1,271	1,655	2,473
General and administrative (including equity-based compensation expense of $112,252, $97,877, and $102,421 in 2014, 2015, and 2016, respectively)	216,533	233,697	239,324
Contract termination and rig stacking	—	38,531	—
Total operating expenses	1,420,898	2,164,572	2,720,326
Operating income (loss)	1,299,734	1,790,286	(975,801)
Other income (expenses):			
Equity in earnings of unconsolidated affiliate	—	—	485
Interest	(160,051)	(234,400)	(253,552)
Loss on early extinguishment of debt	(20,386)	—	(16,956)
Total other expenses	(180,437)	(234,400)	(270,023)
Income (loss) before income taxes	1,119,297	1,555,886	(1,245,824)
Provision for income tax (expense) benefit	(445,672)	(575,890)	496,376
Income (loss) from continuing operations	673,625	979,996	(749,448)
Discontinued operations:			
Income from sale of discontinued operations, net of income tax expense of $1,354 in 2014	2,210	—	—
Net income (loss) and comprehensive income (loss) including noncontrolling interest	675,835	979,996	(749,448)
Net income and comprehensive income attributable to noncontrolling interest	2,248	38,632	99,368
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ 673,587	941,364	(848,816)
Earnings (loss) per common share—basic:			
Continuing operations	$ 2.56	3.43	(2.88)
Discontinued operations	0.01	—	—
Total	$ 2.57	3.43	(2.88)
Earnings (loss) per common share—assuming dilution:			
Continuing operations	$ 2.56	3.43	(2.88)
Discontinued operations	0.01	—	—
Total	$ 2.57	3.43	(2.88)
Weighted average number of shares outstanding:			
Basic	262,054	274,123	294,945
Diluted	262,068	274,143	294,945

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Equity

Years Ended December 31, 2014, 2015, and 2016

(In thousands)

	Common Stock		Additional	Accumulated	Noncontrolling	Total
	Shares	Amount	paid-in capital	earnings	interest	equity
Balances, December 31, 2013	262,050	$ 2,620	3,402,180	193,860	—	3,598,660
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	22	1	(142)	—	—	(141)
Equity-based compensation	—	—	111,687	—	565	112,252
Issuance of common units in subsidiary - Antero Midstream Partners LP	—	—	—	—	1,087,224	1,087,224
Net income and comprehensive income	—	—	—	673,587	2,248	675,835
Balances, December 31, 2014	262,072	2,621	3,513,725	867,447	1,090,037	5,473,830
Issuance of common stock in public offering, net of underwriter discounts and offering costs	14,700	147	537,685	—	—	537,832
Issuance of common units in Antero Midstream Partners LP	—	—	—	—	240,703	240,703
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income tax withholdings	264	2	(4,627)	—	—	(4,625)
Issuance of common units in Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income tax withholdings	—	—	(17,272)	—	12,466	(4,806)
Equity-based compensation	—	—	93,300	—	4,577	97,877
Net income and comprehensive income	—	—	—	941,364	38,632	979,996
Distributions to noncontrolling interests	—	—	—	—	(34,129)	(34,129)
Balances, December 31, 2015	277,036	2,770	4,122,811	1,808,811	1,352,286	7,286,678
Issuances of common stock, net of offering costs	36,493	365	1,012,066	—	—	1,012,431
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	1,348	14	(21,274)	—	—	(21,260)
Issuance of common units by Antero Midstream Partners LP, net of offering costs	—	—	—	—	65,395	65,395
Issuance of common units in Antero Midstream Partners LP upon vesting of equity-based compensation awards, net of units withheld for income taxes	—	—	(15,190)	—	9,555	(5,635)
Sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation, net of tax	—	—	106,659	—	6,419	113,078
Equity-based compensation	—	—	94,409	—	8,012	102,421
Net income (loss) and comprehensive income (loss)	—	—	—	(848,816)	99,368	(749,448)
Distributions to noncontrolling interests	—	—	—	—	(75,082)	(75,082)
Balances, December 31, 2016	314,877	$ 3,149	5,299,481	959,995	1,465,953	7,728,578

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Cash Flows

Years Ended December 31, 2014, 2015, and 2016

(In thousands)

	Year Ended December 31,		
	2014	2015	2016
Cash flows from operating activities:			
Net income (loss) including noncontrolling interest	$ 675,835	979,996	(749,448)
Adjustment to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion	479,167	711,418	812,346
Impairment of unproved properties	15,198	104,321	162,935
Derivative fair value (gains) losses	(868,201)	(2,381,501)	514,181
Gains on settled derivatives	135,784	856,572	1,003,083
Deferred income tax expense (benefit)	445,672	575,890	(485,392)
Gain on sale of assets	(40,000)	—	(97,635)
Equity-based compensation expense	112,252	97,877	102,421
Loss on early extinguishment of debt	20,386	—	16,956
Gain on sale of discontinued operations	(3,564)	—	—
Deferred income tax expense—discontinued operations	1,354	—	—
Equity in earnings of unconsolidated affiliate	—	—	(485)
Distributions of earnings from unconsolidated affiliates	—	—	7,702
Other	6,433	31,741	(12,488)
Changes in current assets and liabilities:			
Accounts receivable	(45,593)	(3,201)	39,857
Accrued revenue	(94,733)	63,316	(133,718)
Other current assets	(2,891)	(2,221)	1,774
Accounts payable	(20,681)	(8,536)	7,365
Accrued liabilities	95,066	36,377	18,853
Revenue distributions payable	85,763	(52,403)	34,040
Other current liabilities	1,016	6,166	(1,091)
Net cash provided by operating activities	998,263	1,015,812	1,241,256
Cash flows used in investing activities:			
Additions to proved properties	(64,066)	—	(134,113)
Additions to unproved properties	(777,422)	(198,694)	(611,631)
Drilling and completion costs	(2,477,150)	(1,651,282)	(1,327,759)
Additions to water handling and treatment systems	(196,675)	(131,051)	(188,188)
Additions to gathering systems and facilities	(558,037)	(360,287)	(231,044)
Additions to other property and equipment	(13,218)	(6,595)	(2,694)
Investment in unconsolidated affiliate	—	—	(75,516)
Change in other assets	(3,082)	9,750	3,977
Proceeds from asset sales	—	40,000	171,830
Net cash used in investing activities	(4,089,650)	(2,298,159)	(2,395,138)
Cash flows from financing activities:			
Issuance of common stock	—	537,832	1,012,431
Issuance of common units by Antero Midstream Partners LP	1,087,224	240,703	65,395
Proceeds from sale of common units of Antero Midstream Partners LP held by Antero Resources Corporation	—	—	178,000
Issuance of senior notes	1,102,500	750,000	1,250,000
Repayment of senior notes	(260,000)	—	(525,000)
Repayments on bank credit facilities, net	1,442,000	(403,000)	(677,000)
Make-whole premium on debt extinguished	(17,383)	—	(15,750)
Payments of deferred financing costs	(31,543)	(17,293)	(18,759)
Distributions to noncontrolling interest in consolidated subsidiary	—	(34,129)	(75,082)
Employee tax withholding for settlement of equity compensation awards	(142)	(9,431)	(26,895)
Other	(2,777)	(4,841)	(5,321)
Net cash provided by financing activities	3,319,879	1,059,841	1,162,019
Net increase (decrease) in cash and cash equivalents	228,492	(222,506)	8,137
Cash and cash equivalents, beginning of period	17,487	245,979	23,473
Cash and cash equivalents, end of period	$ 245,979	23,473	31,610
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 163,055	219,945	239,369
Supplemental disclosure of noncash investing activities:			
Increase (decrease) in accounts payable and accrued liabilities for additions to property and equipment	$ 181,591	(169,783)	(152,093)

See accompanying notes to consolidated financial statements.

(1) Business and Organization

Antero Resources Corporation (individually referred to as "Antero") and its consolidated subsidiaries (collectively referred to as the "Company") are engaged in the exploration, development, and acquisition of natural gas, NGL, and oil properties in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs, and oil from unconventional formations. Through its consolidated subsidiary, Antero Midstream Partners LP, a publicly-traded limited partnership ("Antero Midstream" or "the Partnership"), the Company has water handling and treatment operations and midstream operations in the Appalachian Basin. The Company's corporate headquarters are located in Denver, Colorado.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). In the opinion of management, the accompanying consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of December 31, 2015 and 2016, and the results of its operations and its cash flows for the years ended December 31, 2014, 2015, and 2016. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is identical to its comprehensive income or loss. The Company's balance sheets and statements of cash flows for prior periods include reclassifications within current liabilities that were made to conform to the 2016 presentation.

As of the date these financial statements were filed with the SEC, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified except for those identified in note 20.

(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 for which the Company is the primary beneficiary. The Company consolidates Antero Midstream as it is the primary beneficiary based on its significant ownership interest in Antero Midstream, the significance of the Company's activities to Antero Midstream's operations, and its influence over Antero Midstream through the presence of Company executives and directors that serve on the board of directors of Antero Midstream's general partner. All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements. Noncontrolling interest in the Company's consolidated financial statements represents the interests in Antero Midstream which are owned by the public and Antero Midstream's general partner. An affiliate of Antero owns the general partner interest in Antero Midstream. Noncontrolling interest is included as a component of equity in the Company's consolidated balance sheets.

Investments in entities for which the Company exercises significant influence, but not control, are accounted for under the equity method. Such investments are included in Other assets on the Company's consolidated balance sheets. Income from such investments is included in Equity in earnings of unconsolidated affiliate on the Company's consolidated statements of operations and cash flows.

(c) Use of Estimates

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

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

(d) Risks and Uncertainties

Historically, the markets for natural gas, NGLs, and oil have experienced significant price fluctuations. Price fluctuations can result from variations in weather, regional levels of production, availability of transportation capacity to other regions of the country, 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.

(f) Oil and Gas Properties

The Company accounts for its natural gas, NGLs, and crude oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the Company determines that the well does not contain reserves in commercially viable quantities. The Company reviews exploration costs related to wells-in-progress at the end of each quarter and makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. The Company incurred no such charges during the years ended December 31, 2014, 2015, and 2016. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties are assessed for impairment on a property-by-property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on, or otherwise attributed, to the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties for leases which have expired, or are expected to expire, was $15 million, $104 million, and $163 million for the years ended December 31, 2014, 2015, and 2016, respectively.

The Company evaluates the carrying amount of its proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company would estimate the fair value of its properties and record an impairment charge for any excess of the carrying amount of the properties over the estimated fair value of the properties. Factors used to estimate fair value may include estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a commensurate discount rate. Because estimated undiscounted future cash flows have exceeded the carrying value of the Company's proved properties at the end of each quarter, it has not been necessary for the Company to estimate the fair value of its properties under GAAP for successful efforts accounting. As a result, the Company has not recorded any impairment expenses associated with its proved properties during the year ended December 31, 2016. Additionally, the Company did not record any impairment expenses for proved properties during the years ended December 31, 2014 and 2015.

At December 31, 2016, the Company did not have capitalized costs related to exploratory wells-in-progress which have been deferred for longer than one year pending determination of proved reserves.

The provision for depletion of oil and gas properties is calculated on a geological reservoir basis using the units-of-production method. Depletion expense for oil and gas properties was $419 million, $615 million, and $700 million for the years ended December 31, 2014, 2015, and 2016, respectively.

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

Expenditures for construction, installation, major additions, and improvements to property, plant, and equipment that is not directly related to production are capitalized, whereas minor replacements, maintenance, and repairs are expensed as incurred. Gathering pipelines and compressor stations are depreciated using the straight-line method over their estimated useful lives of 20 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 $53 million, $87 million, and $101 million for the years ended December 31, 2014, 2015, and 2016, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

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

The Company evaluates its long-lived assets other than natural gas properties for impairment when events or changes in circumstances indicate that the related carrying values of the assets may not be recoverable. Generally, the basis for making such assessments is undiscounted future cash flow projections for the assets being assessed. If the carrying values of the assets are deemed not recoverable, the carrying values are reduced to the estimated fair values, which are based on discounted future cash flows or other techniques, as appropriate. There were no impairments for such assets during the years ended December 31, 2014, 2015, and 2016.

(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 $5.9 million, $7.7 million, and $8.9 million for the years ended December 31, 2014, 2015, and 2016, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(j) Deferred Financing Costs

Deferred financing costs represent loan origination fees, initial purchasers' discounts, and other 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 using the straight-line method. The Company charges expense for unamortized deferred financing costs if credit facilities are retired prior to their maturity date. At December 31, 2016, the Company had $14 million of unamortized deferred financing costs included in other long-term assets, and $48 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 $11 million, $10 million, and $16 million for the years ended December 31, 2014, 2015, and 2016, 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 position.

The Company records derivative instruments on the consolidated balance sheets as either an asset or liability 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 ("ARO") relate primarily to its obligation to plug and abandon oil and gas wells at the end of their lives. The ARO is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations, which are then discounted at the Company's credit-adjusted, risk-free interest rate. Revisions to estimated ARO 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. If an obligation is settled for an amount other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

The Company delivers natural gas through its gathering assets and delivers water through its water handling and treatment assets and may become obligated by regulatory or other requirements to remove certain facilities or perform other remediation upon retirement of these assets. However, the Company cannot reasonably predict when production from its producing properties will cease. In the absence of such information, management is not able to make a reasonable estimate of when future dismantlement and removal dates will occur; therefore, the Company has not recorded asset retirement obligations related to its gathering and compression and water handling and treatment assets.

(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, 2015 and 2016, the Company did not have a material amount accrued for any environmental liabilities, nor has the Company been cited for any environmental violations that are likely to have a material adverse effect on future capital expenditures or operating results of the Company.

(n) Natural Gas, NGLs, and Oil Revenues

Sales of natural gas, NGLs, and crude oil are recognized when the products are delivered to the purchaser and title transfers to the purchaser. Payment is generally received one month after the sale has occurred. Variances between estimated sales and actual amounts received are recorded in the month payment is received and are not material. The Company recognizes natural gas revenues based on its entitlement share of natural gas that is produced based on its working interests in the properties. The Company records a revenue distribution payable to the extent it receives more than its proportionate share of natural gas revenues. At December 31, 2015 and 2016, the Company had no imbalance positions.

(o) Concentrations of Credit Risk

The Company's revenues are derived principally from uncollateralized sales to purchasers in the oil and gas industry. The concentration of credit risk in a single industry 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, 2014, 2015, and 2016 are as follows:

	2014	2015	2016
Company A	5 %	19 %	29 %
Company B	—	—	13
Company C	16	13	3
Company D	29	18	2
Company E	12	9	1
All others	38	41	52
	100%	100%	100%

Although a substantial portion of the Company's production is purchased by these major customers, the Company does not believe the loss of any one or several customers would have a material adverse effect on its business, as other customers or markets would be accessible.

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 fifteen different counterparties, all of which are a lender under Antero's Credit Facility. The fair value of the Company's commodity derivative contracts of approximately $1.6 billion at December 31, 2016 includes the following receivables by bank counterparty: Morgan Stanley—$551 million; Barclays—$392 million; JP Morgan—$306 million; Wells Fargo—$159 million; Scotiabank—$136 million; Canadian Imperial Bank of Commerce—$58 million; Toronto Dominion Bank—$32 million; Fifth Third Bank—$12 million; Bank of Montreal—$10 million; and Capital One—$2 million. The credit ratings of certain of these banks were downgraded in recent years because of the sovereign debt crisis in Europe. 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, 2016 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.

(p) 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.

(q) Fair Value Measurements

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

(r) Industry Segments and Geographic Information

Management has evaluated how the Company is organized and managed and has identified the following segments: (1) the exploration, development, and production of natural gas, NGLs, and oil; (2) gathering and processing; (3) water handling and treatment; and (4) marketing of excess firm transportation capacity.

All of the Company's assets are located in the United States and substantially all of its production revenues are attributable to customers located in the United States; however, some of the Company's production revenues are attributable to customers who resell the Company's production to third parties located in foreign countries.

(s) Marketing Revenues and Expenses

Marketing revenues and expenses represent activities undertaken by the Company to purchase and sell third-party natural gas and NGLs and to market its excess firm transportation capacity in order to utilize this excess capacity. Marketing revenues include sales of purchased third-party gas and NGLs, as well as revenues from the release of firm transportation capacity to others. 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.

(t) Earnings (loss) Per Common Share

Earnings (loss) per common share for each period is computed by dividing net income (loss) from continuing operations attributable to Antero or income from discontinued operations, as applicable, by the basic weighted average number of shares outstanding during such period. Earnings (loss) per common share—assuming dilution for each period is computed 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 year were the end of the performance period required for the vesting of such performance share unit 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 antidilutive. The following is a reconciliation of the Company's basic weighted average shares outstanding to diluted weighted average shares outstanding during the periods presented (in thousands):

	Year ended December 31,		
	2014	2015	2016
Basic weighted average number of shares outstanding	262,054	274,123	294,945
Add: Dilutive effect of non-vested restricted stock units	14	20	—
Add: Dilutive effect of outstanding stock options	—	—	—
Add: Dilutive effect of performance stock units	—	—	—
Diluted weighted average number of shares outstanding	262,068	274,143	294,945
Weighted average number of outstanding equity awards excluded from calculation of diluted earnings per common share(1):			
Non-vested restricted stock and restricted stock units	1,444	2,264	6,740
Outstanding stock options	73	553	702
Performance stock units	—	—	659

(1) The potential dilutive effects of these awards were excluded from the computation of earnings per common share—assuming dilution because the inclusion of these awards would have been anti-dilutive. When the Company incurs a net loss, all outstanding equity awards are excluded from the calculation of diluted loss per common share because the inclusion of these awards would be anti-dilutive.

(u) New Accounting Principle

On March 30, 2016, the Financial Accounting Standards Board (the "FASB") issued ASU No. 2016-09, Stock Compensation–Improvements to Employee Share-Based Payment Accounting. This standard simplifies or clarifies several aspects of the accounting for equity-based payment awards, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Certain of these changes are required to be applied retrospectively, while other changes are required to be applied prospectively. The Company elected to early-adopt the standard as of January 1, 2016.

As permitted by this standard, the Company has elected to account for forfeitures in compensation cost as they occur. This standard also permits an entity to withhold income taxes upon settlement of equity-classified awards at up to the maximum statutory tax rate and requires that such payments be classified as financing activities on the statement of cash flows.

As a result of adopting this standard, cash outflows attributable to tax withholdings on the net settlement of equity-classified awards have been reclassified from operating cash flows to financing cash flows. The retrospective adjustment to the consolidated statement of cash flows for the year ended December 31, 2015 is as follows (in thousands):

	As Previously Reported Year Ended December 31, 2015	Adjustment Effect	As Adjusted Year Ended December 31, 2015
Changes in accrued liabilities	$ 26,946	9,431	36,377
Employee tax withholding for settlement of equity compensation awards	—	(9,431)	(9,431)

(3) Antero Midstream Partners LP

In 2014, the Company formed Antero Midstream to own, operate, and develop midstream assets to service Antero's production. Antero Midstream's assets consist of gathering pipelines, compressor stations, and water handling and treatment facilities, through which it provides services to Antero under long-term, fixed-fee contracts. Antero Resources Midstream Management LLC ("Midstream Management"), a wholly-owned subsidiary of Antero Resources Investment LLC ("Antero Investment"), owns the general partnership interest in Antero Midstream, which allows Midstream Management to manage the business and affairs of Antero Midstream. Midstream Management is also the managing member of the entity that holds incentive distribution rights in Antero Midstream. Antero Midstream is an unrestricted subsidiary as defined by Antero's bank credit facility and, as such, Antero Midstream and its subsidiaries are not guarantors of Antero's obligations, and Antero is not a guarantor of Antero Midstream's obligations (see note 17).

On September 23, 2015, Antero contributed (i) all of the outstanding limited liability company interests of Antero Water LLC ("Antero Water") to Antero Midstream and (ii) all of the assets, contracts, rights, permits and properties owned or leased by Antero and used primarily in connection with the construction, ownership, operation, use or maintenance of Antero's advanced waste water treatment complex under construction in Doddridge County, West Virginia, to Antero Treatment LLC ("Antero Treatment"), a subsidiary of Antero Midstream (collectively, (i) and (ii) are referred to herein as the "Contributed Assets").

In consideration for the Contributed Assets, Antero Midstream (i) paid to Antero a cash distribution equal to $552 million, less $171 million of assumed debt, (ii) issued to Antero 10,988,421 common units representing limited partner interests in Antero Midstream, (iii) distributed to Antero proceeds of approximately $241 million from a private placement of Antero Midstream common units, and (iv) has agreed to pay Antero (a) $125 million in cash if Antero Midstream delivers 176,295,000 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 delivers 219,200,000 barrels or more of fresh water during the period between January 1, 2018 and December 31, 2020. Antero Midstream borrowed $525 million on its bank credit facility in connection with this transaction.

On March 30, 2016, Antero sold 8,000,000 of its Antero Midstream common units for $178 million. The sale of the units is reflected in stockholders' equity as additional paid-in capital, net of taxes.

On May 26, 2016, Antero Midstream purchased a 15% equity interest in a regional gathering pipeline, in which Antero is an anchor shipper, for approximately $45 million. This investment is accounted for under the equity method.

During the third quarter of 2016, the Partnership entered into an Equity Distribution Agreement (the "Distribution Agreement"). Pursuant to the terms of the agreement, the Partnership may sell, from time to time through brokers acting as its sales agents, common units representing limited partner interests having an aggregate offering price of up to $250 million. Sales of the common units are made by means of ordinary brokers' transactions on the New York Stock Exchange, at market prices, in block transactions, or as otherwise agreed to between the Partnership and the sales agents. Proceeds are used for general partnership purposes, which may include repayment of indebtedness and funding working capital or capital expenditures. The Partnership is under no obligation to offer and sell common units under the Distribution Agreement. During the year ended December 31, 2016, the Partnership issued and sold 2,391,595 common units under the Distribution Agreement, resulting in net proceeds of $65.4 million after deducting commissions and other offering costs. The Partnership used the net proceeds from the sales for general partnership purposes. As of December 31, 2016, Antero Midstream had the capacity to issue additional common units under the Distribution Agreement up to an aggregate amount of $183.8 million.

At December 31, 2015 and December 31, 2016, Antero owned approximately 66.3% and 60.9% of the limited partner interests of Antero Midstream, respectively.

(4) Sale of Piceance and Arkoma Properties—Discontinued Operations

In 2012, the Company sold its Piceance Basin assets in Colorado and its Arkoma Basin assets in Oklahoma. Pre-tax losses recognized in discontinued operations at the time of the transactions were adjusted downward in 2014 by $3.6 million for the resolution of certain liabilities recorded at the time of the sales and settlement of final contractual purchase price adjustments.

(5) Sales of Assets

Sale of Pennsylvania Leasehold Acreage

On December 16, 2016, the Company closed the sale of approximately 17,000 net acres primarily located in Washington and Westmoreland Counties, Pennsylvania. The acreage was outside of the Company's infrastructure build-out and was not expected to be developed in the near future. Included in the sale were several producing wells and a gathering pipeline belonging to Antero Midstream. Total proceeds from the sale were $169.8 million (subject to customary purchase price adjustments), which includes the proceeds received by Antero Midstream. As a result of the sale, the Company recognized a gain on the sale of assets of $99.0 million for the year ended December 31, 2016.

Sale of Appalachian Gathering Assets

On March 26, 2012, the Company closed the sale of a portion of its Marcellus Shale gathering system assets in West Virginia along with exclusive rights to gather the Company's gas for a 20 year period within an area of dedication to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together "Crestwood") for $375 million. During the first seven years of the contract, the Company is committed to deliver minimum annual volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies.

Under the terms of the agreement, the Company earned additional proceeds of $40 million by meeting certain volume thresholds by December 31, 2014. The Company recognized the $40 million gain on the sale of assets in 2014. The amount was paid by Crestwood in 2015.

(6) Accrued Liabilities

Accrued liabilities as of December 31, 2015 and 2016 consisted of the following items (in thousands):

	December 31, 2015	December 31, 2016
Accrued capital expenditures	$ 271,542	159,811
Accrued gathering, compression, processing, and transportation expenses	59,962	75,223
Accrued marketing expenses	38,136	52,822
Accrued interest expense	26,391	35,533
Other accrued liabilities	92,294	70,414
	$ 488,325	393,803

(7) Long-Term Debt

Long-term debt was as follows at December 31, 2015 and 2016 (in thousands):

	December 31, 2015	December 31, 2016
Antero:		
Bank credit facility(a)	$ 707,000	440,000
6.00% senior notes due 2020(b)	525,000	—
5.375% senior notes due 2021(c)	1,000,000	1,000,000
5.125% senior notes due 2022(d)	1,100,000	1,100,000
5.625% senior notes due 2023(e)	750,000	750,000
5.00% senior notes due 2025(f)	—	600,000
Net unamortized premium	6,513	1,749
Net unamortized debt issuance costs	(39,731)	(37,690)
Antero Midstream:		
Bank credit facility(h)	620,000	210,000
5.375% senior notes due 2024 (i)	—	650,000
Net unamortized debt issuance costs	—	(10,086)
	$ 4,668,782	4,703,973

Antero Resources Corporation

(a) Senior Secured Revolving Credit Facility

Antero has a senior secured revolving bank credit facility (the "Credit Facility") with a consortium of bank lenders. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of Antero's assets and are subject to regular semiannual redeterminations. At December 31, 2016, the borrowing base was $4.75 billion and lender commitments were $4.0 billion. The next redetermination of the borrowing base is scheduled to occur in April 2017. The maturity date of the Credit Facility is May 5, 2019.

The Credit Facility is ratably secured by mortgages on substantially all of Antero's properties and guarantees from Antero's restricted subsidiaries, as applicable. 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. Antero was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2015 and 2016.

As of December 31, 2016, Antero had an outstanding balance under the Credit Facility of $440 million with a weighted average interest rate of 2.44% and outstanding letters of credit of $710 million. As of December 31, 2015, Antero had an outstanding balance under the Credit Facility of $707 million, with a weighted average interest rate of 2.32%, and outstanding letters of credit of approximately $702 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from 0.375% to 0.50% of the unused portion based on utilization.

(b) 6.00% Senior Notes Due 2020

On December 30, 2016, Antero satisfied and discharged the obligations with respect to its outstanding 6.00% senior notes due 2020 (the "2020" notes) having a principal balance of $525 million at a redemption price of 103% of the principal amount, plus accrued and unpaid interest. The call premium, along with the write-offs of the unamortized issuance premium and deferred financing costs, resulted in a loss of approximately $17 million which was charged to Loss on early extinguishment of debt in the accompanying statement of operations.

(c) 5.375% Senior Notes Due 2021

On November 5, 2013, Antero issued $1 billion of 5.375% senior notes due November 21, 2021 (the "2021 notes") at par. The 2021 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2021 notes rank pari passu to Antero's other outstanding senior notes. The 2021 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. Antero may redeem all or part of the 2021 notes at any time at redemption prices ranging from 104.031% currently to 100.00% on or after November 1, 2019. If Antero undergoes a change of control, the holders of the 2021 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2021 notes, plus accrued and unpaid interest.

(d) 5.125% Senior Notes Due 2022

On May 6, 2014, Antero issued $600 million of 5.125% senior notes due December 1, 2022 (the "2022 notes") at par. On September 18, 2014, Antero issued an additional $500 million of the 2022 notes at 100.5% of par. The 2022 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2022 notes rank pari passu to Antero's other outstanding senior notes. The 2022 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. Antero may redeem all or part of the 2022 notes at any time on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, Antero may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125% of the principal amount of the 2022 notes, plus accrued and unpaid interest. At any time prior to June 1, 2017, Antero may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a "make-whole" premium and accrued and unpaid interest. If Antero undergoes a change of control, the holders of the 2022 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued and unpaid interest.

(e) 5.625% Senior Notes Due 2023

On March 17, 2015, Antero issued $750 million of 5.625% senior notes due June 1, 2023 (the "2023 notes") at par. The 2023 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the Credit Facility. The 2023 notes rank pari passu to Antero's other outstanding senior notes. The 2023 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2023 notes is payable on June 1 and December 1 of each year. Antero may redeem all or part of the 2023 notes at any time on or after June 1, 2018 at redemption prices ranging from 104.219% on or after June 1, 2018 to 100.00% on or after June 1, 2021. In addition, on or before June 1, 2018, Antero may redeem up to 35% of the aggregate principal amount of the 2023 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.625% of the principal amount of the 2023 notes, plus accrued and unpaid interest. At any time prior to June 1, 2018, Antero may also redeem the 2023 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2023 notes plus a "make-whole" premium and accrued and unpaid interest. If Antero undergoes a change of control, the holders of the 2023 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2023 notes, plus accrued and unpaid interest.

(f) 5.00% Senior Notes Due 2025

On December 21, 2016, Antero issued $600 million of 5.00% senior notes due March 1, 2025 (the "2025 notes") at par. The 2025 notes are unsecured and effectively subordinated to the Credit Facility to the extent of the value of the collateral securing the

Credit Facility. The 2025 notes rank pari passu to Antero's other outstanding senior notes. The 2025 notes are guaranteed on a full and unconditional and joint and several senior unsecured basis by Antero's wholly-owned subsidiaries and certain of its future restricted subsidiaries. Interest on the 2025 notes is payable on March 1 and September 1 of each year. Antero may redeem all or part of the 2025 notes at any time on or after March 1, 2020 at redemption prices ranging from 103.750% on or after March 1, 2020 to 100.00% on or after March 1, 2023. In addition, on or before March 1, 2020, Antero may redeem up to 35% of the aggregate principal amount of the 2025 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.00% of the principal amount of the 2025 notes, plus accrued and unpaid interest. At any time prior to March 1, 2020, Antero may also redeem the 2025 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2025 notes plus a "make-whole" premium and accrued and unpaid interest. If Antero undergoes a change of control, the holders of the 2025 notes will have the right to require Antero to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2025 notes, plus accrued and unpaid interest. Proceeds from the 2025 notes were used to redeem the 2020 notes (see note 7(b) above) and for general corporate purposes.

(g) Treasury Management Facility

Antero has a stand-alone revolving note with a lender under the Credit Facility which provides for up to $25 million of cash management obligations in order to facilitate Antero's daily treasury management. Borrowings under the revolving note are secured by the collateral for the Credit Facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on May 1, 2017. At December 31, 2015 and 2016, there were no outstanding borrowings under this facility.

Antero Midstream Partners LP

(h) Senior Secured Revolving Credit Facility – Antero Midstream

Antero Midstream has a secured revolving credit facility (the "Midstream Facility") with a syndicate of bank lenders. At December 31, 2016, lender commitments were $1.5 billion. The maturity date of the Midstream Facility is November 10, 2019.

The Midstream Facility is ratably secured by mortgages on substantially all of the properties of Antero Midstream and guarantees from its restricted subsidiaries, as applicable. The Midstream Facility contains certain covenants, including restrictions on indebtedness and certain distributions to owners, and requirements with respect to leverage and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate, determined by election at the time of borrowing. Antero Midstream was in compliance with all of the financial covenants under the Midstream Facility as of December 31, 2015 and 2016.

As of December 31, 2016, Antero Midstream had an outstanding balance under the Midstream Facility of $210 million with a weighted average interest rate of 2.23%. As of December 31, 2015, Antero Midstream had a total outstanding balance under the Midstream Facility of $620 million with a weighted average interest rate of 1.92%. Commitment fees on the unused portion of the Midstream Facility are due quarterly at rates ranging from 0.25% to 0.375% of the unused facility based on utilization.

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

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

(8) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2015 and 2016 (in thousands).

	2015	2016
Asset retirement obligations—beginning of year	$ 16,614	30,612
Obligations incurred for wells drilled and producing properties acquired	9,213	4,487
Revisions to prior estimates	3,130	(4,836)
Accretion expense	1,655	2,473
Asset retirement obligations—end of year	$ 30,612	32,736

Revisions to prior estimates in 2016 are primarily due to a decrease in the estimated costs to plug and abandon the Company's horizontal wells. Revisions to prior estimates in 2015 are primarily due to a decrease in the estimated economic lives of the Company's wells as a result of the decrease in commodity prices during 2015. Asset retirement obligations are included in other liabilities on the consolidated balance sheets.

(9) Equity-Based Compensation

Antero is authorized to grant up to 16,906,500 shares of common stock to employees and directors of the Company under the Antero Resources Corporation Long-Term Incentive Plan (the "Plan"). The Plan allows equity-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent awards, and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of Antero's Board of Directors. A total of 8,449,452 shares were available for future grant under the Plan as of December 31, 2016.

Antero Midstream's general partner is authorized to grant up to 10,000,000 common units representing limited partner interests in Antero Midstream under the Antero Midstream Partners LP Long-Term Incentive Plan (the "Midstream Plan") to certain officers, employees, and consultants of Antero and Antero Midstream's general partner, and its non-employee directors. A total of 7,937,930 common units are available for future grant under the Midstream Plan as of December 31, 2016.

The Company's equity-based compensation expense, by type of award, is as follows for the years ended December 31, 2014, 2015, and 2016 (in thousands):

	Year ended December 31,		
	2014	2015	2016
Profits interests awards	$ 83,615	37,620	—
Restricted stock unit awards	25,624	40,663	73,081
Stock options	501	2,155	2,578
Performance share unit awards	—	—	8,685
Antero Midstream phantom unit awards	2,360	17,126	16,095
Equity awards issued to directors	152	313	1,982
Total expense	$ 112,252	97,877	102,421

Profits Interests Awards

Certain profits interest awards historically held by certain of the Company's officers and employees were fully vested as of December 31, 2015. All available profits interest awards were made prior to the date of the Company's IPO in 2013, and no additional profits interest awards have been made since the Company's IPO.

Restricted Stock and Restricted Stock Unit Awards

Restricted stock and restricted stock unit awards vest subject to the satisfaction of service requirements. Expense related to each restricted stock and 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 through reversal of expense on awards that were forfeited during the period. The grant date fair values of these awards are determined based on the closing price of the Company's common stock on the date of the grant. A summary of restricted stock and restricted stock unit awards activity for the year ended December 31, 2016 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2015	6,529,459	$ 33.48	$ 142,342
Granted	1,241,710	$ 27.06	
Vested	(2,123,282)	$ 34.95	
Forfeited	(294,440)	$ 26.89	
Total awarded and unvested—December 31, 2016	5,353,447	$ 31.77	$ 126,609

Intrinsic values are based on the closing price of the Company's stock on the referenced dates. Unamortized expense of $130.2 million at December 31, 2016 is expected to be recognized over a weighted average period of approximately 2.0 years.

Stock Options

Stock options granted under the Plan vest over periods from one to four years and 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 through reversal of expense on awards that were forfeited during the period. Stock options are granted with an exercise price equal to or greater than the market price of the Company's common stock on the date of grant. A summary of stock option activity for the year ended December 31, 2016 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at December 31, 2015	720,887	$ 50.44	9.14	$ —
Granted	—	$ —		
Exercised	—	—		
Forfeited	(32,958)	$ 50.00		
Expired	—	—		
Outstanding at December 31, 2016	687,929	$ 50.46	8.12	$ —
Vested or expected to vest as of December 31, 2016	687,929	$ 50.46	8.12	$ —
Exercisable at December 31, 2016	217,882	$ 51.17	7.87	$ —

Intrinsic value is based on the exercise price of the options and the closing price of the Company's stock on the referenced dates.

A Black-Scholes option-pricing model is used to determine the grant-date fair value of stock options. Expected volatility was derived from the volatility of the historical stock prices of a peer group of similar publicly traded companies' stock prices as the Company 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.

The following table presents information regarding the weighted average fair value for options granted during the years ended December 31, 2014 and 2015 and the assumptions used to determine fair value.

	Year ended December 31, 2014	Year ended December 31, 2015
Dividend yield	— %	— %
Volatility	40 %	40 %
Risk-free interest rate	1.75 %	1.66 %
Expected life (years)	5.50	6.25
Weighted average fair value of options granted	$ 20.55	$ 14.74

As of December 31, 2016, there was $5.4 million of unamortized equity-based compensation expense related to nonvested stock options. That expense is expected to be recognized over a weighted average period of approximately 2.2 years.

Performance Share Unit Awards

Performance Share Unit Awards Based on Price Targets

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

Performance Share Unit Awards Based on Total Shareholder Return

In the second quarter of 2016, the Company granted PSUs to certain of its employees and executive officers which vest based on the total shareholder return ("TSR") of the Company's common stock relative to the TSR of a peer group of companies over a three-year performance period. The number of performance shares which may ultimately be earned ranges from zero to 200% of the PSUs granted. Expense related to these PSUs is recognized on a straight-line basis over three years.

Summary Information for Performance Share Unit Awards

A summary of PSU activity for the year ended December 31, 2016 is as follows:

	Number of units	Weighted average grant date fair value
Total awarded and unvested—December 31, 2015	—	$ —
Granted	790,890	$ 29.77
Vested	—	$ —
Forfeited	(5,589)	$ 32.97
Total awarded and unvested—December 31, 2016	785,301	$ 29.75

The grant-date fair values of 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' stock prices. 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 following table presents information regarding the weighted average fair value for PSUs granted during the year ended December 31, 2016 and the assumptions used to determine the fair values.

	Year ended December 31, 2016
Dividend yield	— %
Volatility	45 %
Risk-free interest rate	1.01 %
Weighted average fair value of awards granted	$ 29.77

As of December 31, 2016, there was $14.7 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 2.1 years.

Antero Midstream Partners Phantom Unit Awards

Phantom units granted by Antero Midstream vest subject to the satisfaction of service requirements, upon the completion of which common units in Antero Midstream are delivered to the holder of the phantom units. These phantom units are treated, for accounting purposes, as if Antero Midstream distributed the units to Antero. Antero recognizes compensation expense as the units are granted to employees, and a portion of the expense is allocated to Antero Midstream. Expense related to each phantom unit award is recognized on a straight-line basis over the requisite service period of the entire award. Forfeitures are accounted for as they occur through reversal of expense on awards that were forfeited during the period. The grant date fair values of these awards are determined based on the closing price of Antero Midstream's common units on the date of grant. A summary of phantom unit awards activity for the year ended December 31, 2016 is as follows:

	Number of units	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested—December 31, 2015	1,667,832	$ 28.97	$ 38,060
Granted	297,356	$ 21.41	
Vested	(524,659)	$ 28.95	
Forfeited	(108,568)	$ 28.66	
Total awarded and unvested—December 31, 2016	1,331,961	$ 27.31	$ 41,131

Intrinsic values are based on the closing price of Antero Midstream's common units on the referenced dates. Unamortized expense of $33.2 million at December 31, 2016 is expected to be recognized over a weighted average period of approximately 2.1 years.

(10) Financial Instruments

The carrying values of accounts receivable and accounts payable at December 31, 2015 and 2016 approximated market value because of their short-term nature. The carrying values of the amounts outstanding under the Credit Facility and Midstream Facility at December 31, 2015 and 2016 approximated fair value because the variable interest rates are reflective of current market conditions.

Based on Level 2 market data inputs, the fair value of the Company's senior notes was approximately $2.6 billion at December 31, 2015 and $3.5 billion at December 31, 2016. Based on Level 2 market data inputs, the fair value of Antero Midstream's senior notes was approximately $657 million at December 31, 2016.

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

(11) Derivative Instruments

(a) Commodity Derivatives

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 held for trading purposes. To the extent that changes occur in the market prices of natural gas, NGLs, and oil, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas, NGLs, and oil recognized upon the ultimate sale of the Company's production.

The Company was party to various fixed price commodity swap contracts that settled during the years ended December 31, 2014, 2015, and 2016. The Company enters into these swap contracts when management believe that favorable future sales prices for the Company's production can be secured. Under these swap agreements, when actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the difference to the counterparty. When actual commodity prices are below the contractually provided fixed price, the Company receives the difference from the counterparty. When actual commodity prices are above the contractually provided fixed price, the Company pays the difference to the counterparty. In addition to fixed price swap contracts, 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 at which the Company sells a portion of its natural gas production. The Company's derivative swap 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, 2016, the Company's fixed price natural gas and NGLs swap positions from January 1, 2017 through December 31, 2022 were as follows (abbreviations in the table refer to the index to which the swap position is tied, as follows: NYMEX=Henry Hub; CGTLA=Columbia Gas Louisiana Onshore; CCG=Chicago City Gate; Mont Belvieu-Ethane=Mont Belvieu Purity Ethane; Mont Belvieu-Propane=Mont Belvieu Propane; NYMEX-WTI=West Texas Intermediate):

	Natural gas MMbtu/day	Oil Bbls/day	Natural Gas Liquids Bbls/day	Weighted average index price
Three months ending March 31, 2017:				
NYMEX ($/MMBtu)	1,370,000	—	—	$ 3.52
CGTLA ($/MMBtu)	420,000	—	—	$ 4.39
CCG ($/MMBtu)	70,000	—	—	$ 4.76
NYMEX-WTI ($/Bbl)	—	3,000	—	$ 54.75
Mont Belvieu-Ethane ($/Gallon)	—	—	20,000	$ 0.25
Mont Belvieu-Propane ($/Gallon)	—	—	27,500	$ 0.40
Total	1,860,000	3,000	47,500	
Three months ending June 30, 2017:				
NYMEX ($/MMBtu)	1,370,000	—	—	$ 3.26
CGTLA ($/MMBtu)	420,000	—	—	$ 4.13
CCG ($/MMBtu)	70,000	—	—	$ 4.38
NYMEX-WTI ($/Bbl)	—	3,000	—	$ 54.75
Mont Belvieu-Ethane ($/Gallon)	—	—	20,000	$ 0.25
Mont Belvieu-Propane ($/Gallon)	—	—	27,500	$ 0.38
Total	1,860,000	3,000	47,500	
Three months ending September 30, 2017:				
NYMEX ($/MMBtu)	1,370,000	—	—	$ 3.33
CGTLA ($/MMBtu)	420,000	—	—	$ 4.20
CCG ($/MMBtu)	70,000	—	—	$ 4.45
NYMEX-WTI ($/Bbl)	—	3,000	—	$ 54.75
Mont Belvieu-Ethane ($/Gallon)	—	—	20,000	$ 0.25
Mont Belvieu-Propane ($/Gallon)	—	—	27,500	$ 0.39
Total	1,860,000	3,000	47,500	
Three months ending December 31, 2017:				
NYMEX ($/MMBtu)	1,370,000	—	—	$ 3.46
CGTLA ($/MMBtu)	420,000	—	—	$ 4.37
CCG ($/MMBtu)	70,000	—	—	$ 4.68
NYMEX-WTI ($/Bbl)	—	3,000	—	$ 54.75
Mont Belvieu-Ethane ($/Gallon)	—	—	20,000	$ 0.25
Mont Belvieu-Propane ($/Gallon)	—	—	27,500	$ 0.40
Total	1,860,000	3,000	47,500	
Year ending December 31, 2018:				
NYMEX ($/MMBtu)	2,002,500		—	$ 3.91
Mont Belvieu-Propane ($/Gallon)	—		2,000	$ 0.65
Total	2,002,500		2,000	
Year ending December 31, 2019:				
NYMEX ($/MMBtu)	2,330,000			$ 3.70
Year ending December 31, 2020:				
NYMEX ($/MMBtu)	1,367,500			$ 3.66
Year ending December 31, 2021:				
NYMEX ($/MMBtu)	660,000			$ 3.35
Year ending December 31, 2022:				
NYMEX ($/MMBtu)	760,000			$ 3.20

As of December 31, 2016, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of TCO to the NYMEX Henry Hub natural gas price, were as follows:

	Natural gas MMbtu/day	Hedged Differential
Year ending December 31, 2017:	125,000	$ (0.49)

As of December 31, 2016, the Company's natural gas basis swap positions, which settle on the pricing index to basis differential of NYMEX Henry Hub to the TCO natural gas price, were as follows:

	Natural gas MMbtu/day	Hedged Differential
Year ending December 31, 2017:	125,000	$ 0.30

(b) Summary

The following is 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, 2015 and 2016. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	December 31, 2015		December 31, 2016	
	Balance sheet location	Fair value (In thousands)	Balance sheet location	Fair value (In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$ 1,009,030	Current assets	73,022
Commodity contracts	Long-term assets	2,108,450	Long-term assets	1,731,063
Total asset derivatives		3,117,480		1,804,085
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	—	Current liabilities	203,635
Commodity contracts	Long-term liabilities	—	Long-term liabilities	234
Total liability derivatives		—		203,869
Net derivatives		$ 3,117,480		1,600,216

The following table presents the gross amounts 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, 2015			December 31, 2016		
	Gross amounts on balance sheet	Gross amounts offset on balance sheet	Net amounts of assets 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	$ 3,163,639	(46,159)	3,117,480	$ 1,914,245	(110,160)	1,804,085
Commodity derivative liabilities	$ —	—	—	$ (324,667)	120,798	(203,869)

The following is a summary of derivative fair value gains (losses) and where such values are recorded in the consolidated statements of operations for the years ended December 31, 2014, 2015, and 2016 (in thousands):

	Statement of operations location	Year ended December 31, 2014	2015	2016
Commodity derivative fair value gains (losses)	Revenue	$ 868,201	2,381,501	(514,181)

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

(12) Contract Termination and Rig Stacking

During the year ended December 31, 2015, the Company incurred $38.5 million of costs for the buy-back and termination of a firm sales contract priced at an unfavorable pricing index and the delay or cancelation of drilling contracts with third-party contractors. There were no such costs incurred during the year ended December 31, 2016.

(13) Income Taxes

For the years ended December 31, 2014, 2015, and 2016, income tax expense (benefit) from continuing operations consisted of the following (in thousands):

	Year ended December 31, 2014	2015	2016
Current income tax benefit	$ —	—	(10,984)
Deferred income tax expense (benefit)	445,672	575,890	(485,392)
Total income tax expense (benefit) from continuing operations	$ 445,672	575,890	(496,376)

Income tax expense (benefit) from continuing operations differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 35% to income from continuing operations for the years ended December 31, 2014, 2015, and 2016 as a result of the following (in thousands):

	Year ended December 31, 2014	2015	2016
Federal income tax expense (benefit)	$ 391,754	544,560	(436,038)
State income tax expense (benefit), net of federal benefit	25,545	26,983	(20,364)
Nondeductible equity-based compensation	29,141	16,441	3,691
Noncontrolling interest in Antero Midstream Partners LP	(787)	(13,521)	(34,780)
Change in valuation allowance	(120)	570	(10,852)
Other	139	857	1,967
Total income tax expense from continuing operations	$ 445,672	575,890	(496,376)

For the years ended December 31, 2014, 2015, and 2016, income tax expense (benefit) was allocated to continuing and discontinued operations as follows (in thousands):

	Year ended December 31, 2014	2015	2016
Continuing operations	$ 445,672	575,890	(496,376)
Discontinued operations and sale of discontinued operations	1,354	—	—
Total income tax expense	$ 447,026	575,890	(496,376)

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, 2015 and 2016 is as follows (in thousands):

	2015	2016
Deferred tax assets:		
Net operating loss carryforwards	$ 521,617	562,355
Minimum tax credit carryforward	11,000	—
Equity-based compensation	16,130	20,344
Other	18,633	16,483
Total deferred tax assets	567,380	599,182
Valuation allowance	(27,209)	(16,357)
Net deferred tax assets	540,171	582,825
Deferred tax liabilities:		
Unrealized gains on derivative instruments	1,167,983	605,487
Oil and gas properties	708,664	866,003
Investment in Antero Midstream Partners LP	34,210	54,052
Other	—	7,500
Total deferred tax liabilities	1,910,857	1,533,042
Net deferred tax liabilities	$ (1,370,686)	(950,217)

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 $27 million and $16 million at December 31, 2015 and 2016, respectively related to NOL carryforwards primarily attributable to states where the Company no longer operates. The valuation allowance was reduced in 2016 due to a change in the estimated amount of state NOLs that can be utilized in the future. The amount of the deferred tax asset considered realizable could be further reduced in the near term if estimates of future taxable income during the carryforward period are revised.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. In 2016, the Company reversed unrecognized benefits recorded in prior years due to the expiration of the applicable statutes of limitations. The removal of the unrecognized benefits does not impact the Company's 2016 effective tax rate. The Company will continue to monitor potential uncertain tax positions, but does not anticipate any changes within the next year. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

	2014	2015	2016
Balance at beginning of year	$ 11,000	11,000	11,000
Reductions for tax positions of prior years	—	—	(11,000)
Balance at end of year	$ 11,000	11,000	—

As of December 31, 2016, the Company's corporate subsidiaries have U.S. Federal and state net operating loss carryforwards (NOLs) of $1.5 billion and $1.4 billion, respectively, which expire at various dates from 2024 to 2036.

The tax years 2013 through 2016 remain open to examination by the U.S. Internal Revenue Service. The Company and its subsidiaries file tax returns with various state taxing authorities; these returns remain open to examination for tax years 2012 through 2016.

(14) Commitments

The following is a schedule of future minimum payments for firm transportation, drilling rig and completion services, processing, gathering and compression, and office and equipment agreements, as well as leases that have remaining lease terms in excess of one year as of December 31, 2016 (in millions).

	Firm transportation (a)	Processing, gathering and compression (b)	Drilling rigs and completion services (c)	Office and equipment (d)	Total
2017	$ 626	373	109	14	1,122
2018	935	289	105	13	1,342
2019	1,086	243	64	10	1,403
2020	1,105	241	—	8	1,354
2021	1,084	223	—	8	1,315
Thereafter	10,551	1,000	—	25	11,576
Total	$ 15,387	2,369	278	78	18,112

(a) Firm Transportation

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

(b) Processing, Gathering, and Compression Service Commitments

The Company has entered into various long-term gas processing agreements for certain of its production that will allow it to realize the value of its NGLs. The minimum payment obligations under the agreements are presented in the table.

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

The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest. The values in the table also include Antero Midstream's commitments for the construction of its advanced waste water treatment complex. The table does not include intracompany commitments.

(c) Drilling Rig Service Commitments

The Company has obligations under agreements with service providers to procure drilling rigs and completion services. The values in the table represent the gross amounts that the Company is committed to pay; however, the Company will record in the consolidated financial statements its proportionate share of costs based on its working interest.

(d) Office and Equipment Leases

The Company leases various office space and equipment, as well as field equipment, under capital and operating lease arrangements. Rental expense under operating leases was $10 million, $9 million, and $9 million for the years ended December 31, 2014, 2015, and 2016, respectively.

(15) Contingencies

The Company is the plaintiff in two nearly identical lawsuits against South Jersey Gas Company and South Jersey Resources Group, LLC (collectively "SJGC") pending in United States District Court in Colorado. The Company filed suit against SJGC seeking relief for breach of contract and damages in the amounts that SJGC has short paid, and continues to short pay, the Company in connection with two long term gas contracts. Under those contracts, SJGC are long term purchasers of some of the Company's natural gas production. Deliveries under the contracts began in October 2011 and the delivery obligation continues through October 2019. SJGC unilaterally breached the contracts claiming that the index prices specified in the contracts, and the index prices at which SJGC paid for deliveries from 2011 through September 2014, are no longer appropriate under the contracts because a market disruption event (as defined by the contract) has occurred and, as a result, a new index price is to be determined by the parties. Beginning in October 2014, SJGC began short paying the Company based on indexes unilaterally selected by SJGC and not the index specified in the contract. The Company contends that no market disruption event has occurred and that SJGC have breached the contracts by failing to pay the Company based on the express price terms of the contracts. Through December 31, 2016, the Company estimates that it is owed approximately $55 million more than SJGC has paid using the indexes unilaterally selected by them.

The Company and Washington Gas Light Company and WGL Midstream, Inc. (collectively, "WGL") are also involved in a pricing dispute involving contracts that the Company began delivering gas under in January 2016. The Company has invoiced WGL at the index price specified in the contract and WGL has paid the Company based on that invoice price; however, WGL asserted that the index price is no longer appropriate under the contracts and 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.

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) Segment Information

See note 2(r) for a description of the Company's determination of its reportable segments. Revenues from gathering and processing and water handling and treatment operations are primarily derived from intersegment transactions for services provided to the Company's exploration and production operations. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and NGLs and to market excess firm transportation capacity to third parties.

Operating segments are evaluated based on their contribution to consolidated results, which is determined by the respective operating income of each segment. General and administrative expenses are allocated to the gathering and processing and water handling and treatment segments based on the nature of the expenses and on a combination of the segments' proportionate share of the Company's consolidated property and equipment, capital expenditures, and labor costs, as applicable. General and administrative expenses related to the marketing segment are not allocated because they are immaterial. Other income, income taxes, and interest expense are primarily managed on a consolidated basis. Intersegment sales are 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, 2014, 2015, and 2016 (in thousands):

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2014:						
Sales and revenues:						
Third-party	$ 2,644,953	6,810	15,265	53,604	—	2,720,632
Intersegment	195	88,936	156,660	—	(245,791)	—
Total	$ 2,645,148	95,746	171,925	53,604	(245,791)	2,720,632
Operating expenses:						
Lease operating	$ 28,041	—	34,737	—	(33,437)	29,341
Gathering, compression, processing, and transportation	536,879	13,497	—	—	(88,963)	461,413
Depletion, depreciation, and amortization	424,684	36,972	16,240	—	—	477,896
General and administrative expense	186,335	22,035	8,331	—	(168)	216,533
Other operating expenses	128,419	1,973	1,888	103,435	—	235,715
Total	1,304,358	74,477	61,196	103,435	(122,568)	1,420,898
Operating income (loss)	$ 1,340,790	21,269	110,729	(49,831)	(123,223)	1,299,734
Segment assets	$ 9,886,214	1,411,470	422,885	10,456	(191,647)	11,539,378
Capital expenditures for segment assets	$ 3,455,079	558,037	196,675	—	(123,223)	4,086,568

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2015:						
Sales and revenues:						
Third-party	$ 3,756,629	12,353	9,647	176,229	—	3,954,858
Intersegment	4,795	218,239	147,085	—	(370,119)	—
Total	$ 3,761,424	230,592	156,732	176,229	(370,119)	3,954,858
Operating expenses:						
Lease operating	$ 35,552	—	49,859	—	(49,400)	36,011
Gathering, compression, processing, and transportation	852,573	25,305	—	—	(218,517)	659,361
Depletion, depreciation, and amortization	622,379	61,552	25,832	—	—	709,763
General and administrative expense	183,675	40,448	10,758	—	(1,184)	233,697
Other operating expenses	222,990	3,811	3,210	299,062	(3,333)	525,740
Total	1,917,169	131,116	89,659	299,062	(272,434)	2,164,572
Operating income (loss)	$ 1,844,255	99,476	67,073	(122,833)	(97,685)	1,790,286
Segment assets	$ 12,426,518	1,470,691	525,004	16,123	(322,843)	14,115,493
Capital expenditures for segment assets	$ 1,954,256	360,287	131,051	—	(97,685)	2,347,909

	Exploration and production	Gathering and processing	Water handling and treatment	Marketing	Elimination of intersegment transactions	Consolidated total
Year ended December 31, 2016:						
Sales and revenues:						
Third-party	$ 1,334,656	16,028	792	393,049	—	1,744,525
Intersegment	18,324	291,916	281,475	—	(591,715)	—
Total	$ 1,352,980	307,944	282,267	393,049	(591,715)	1,744,525
Operating expenses:						
Lease operating	$ 50,651	—	136,386	—	(136,947)	50,090
Gathering, compression, processing, and transportation	1,146,221	28,098	—	—	(291,481)	882,838
Depletion, depreciation, and amortization	709,127	70,847	29,899	—	—	809,873
General and administrative expense	186,672	39,832	14,331	—	(1,511)	239,324
Other operating expenses	241,755	(809)	14,401	499,343	(16,489)	738,201
Total	2,334,426	137,968	195,017	499,343	(446,428)	2,720,326
Operating income (loss)	$ (981,446)	169,976	87,250	(106,294)	(145,287)	(975,801)
Segment assets	$ 12,512,973	1,750,354	615,687	37,890	(661,354)	14,255,550
Capital expenditures for segment assets	$ 2,220,688	231,044	188,188	—	(144,491)	2,495,429

(17) Subsidiary Guarantors

Antero's wholly-owned subsidiaries each have fully and unconditionally guaranteed Antero's senior notes. Antero Midstream and its subsidiaries have been designated unrestricted subsidiaries under the Credit Facility and the indentures governing Antero's senior notes, and do not guarantee any of Antero's obligations (see note 7). In the event a subsidiary guarantor is sold or disposed of (whether by merger, consolidation, the sale of a sufficient amount of its capital stock so that it no longer qualifies as a "Subsidiary" of the Company (as defined in the indentures governing the notes) or the sale of all or substantially all of its assets (other than by lease)) and whether or not the subsidiary guarantor is the surviving entity in such transaction to a person which is not Antero or a restricted subsidiary of Antero, such subsidiary guarantor will be released from its obligations under its subsidiary guarantee if the sale or other disposition does not violate the covenants set forth in the indentures governing the notes.

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

The following Condensed Consolidating Balance Sheets at December 31, 2015 and 2016, and the related Condensed Consolidating Statements of Operations and Comprehensive Income and Condensed Consolidating Statements Cash Flows for the years ended December 31, 2014, 2015, and 2016, present financial information for Antero on a stand-alone basis (carrying its investment in wholly-owned subsidiaries using the equity method), financial information for the subsidiary guarantors, financial information for the non-guarantor subsidiaries, and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. Antero's wholly-owned subsidiaries are not restricted from making distributions to the Parent.

Condensed Consolidating Balance Sheet
December 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 16,590	—	6,883	—	23,473
Accounts receivable, net	76,697	—	2,707	—	79,404
Intercompany receivables	2,138	—	65,712	(67,850)	—
Accrued revenue	128,242	—	—	—	128,242
Derivative instruments	1,009,030	—	—	—	1,009,030
Other current assets	8,087	—	—	—	8,087
Total current assets	1,240,784	—	75,302	(67,850)	1,248,236
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	1,996,081	—	—	—	1,996,081
Proved properties	8,243,901	—	—	(32,795)	8,211,106
Water handling and treatment systems	—	—	565,616	—	565,616
Gathering systems and facilities	16,561	—	1,485,835	—	1,502,396
Other property and equipment	46,415	—	—	—	46,415
	10,302,958	—	2,051,451	(32,795)	12,321,614
Less accumulated depletion, depreciation, and amortization	(1,431,747)	—	(157,625)	—	(1,589,372)
Property and equipment, net	8,871,211	—	1,893,826	(32,795)	10,732,242
Derivative instruments	2,108,450	—	—	—	2,108,450
Investments in subsidiaries	(302,336)	—	—	302,336	—
Contingent acquisition consideration	178,049	—	—	(178,049)	—
Other assets, net	15,661	—	10,904	—	26,565
Total assets	$ 12,111,819	—	1,980,032	23,642	14,115,493
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 58,970	—	10,941	—	69,911
Intercompany payable	65,712	—	2,138	(67,850)	—
Accrued liabilities	402,940	—	85,385	—	488,325
Revenue distributions payable	129,949	—	—	—	129,949
Other current liabilities	18,935	—	150	—	19,085
Total current liabilities	676,506	—	98,614	(67,850)	707,270
Long-term liabilities:					
Long-term debt	4,048,782	—	620,000	—	4,668,782
Deferred income tax liability	1,370,686	—	—	—	1,370,686
Contingent acquisition consideration	—	—	178,049	(178,049)	—
Other liabilities	81,453	—	624	—	82,077
Total liabilities	6,177,427	—	897,287	(245,899)	6,828,815
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,082,745	(1,082,745)	—
Common stock	2,770	—	—	—	2,770
Additional paid-in capital	4,122,811	—	—	—	4,122,811
Accumulated earnings	1,808,811	—	—	—	1,808,811
Total stockholders' equity	5,934,392	—	1,082,745	(1,082,745)	5,934,392
Noncontrolling interest in consolidated subsidiary	—	—	—	1,352,286	1,352,286
Total equity	5,934,392	—	1,082,745	269,541	7,286,678
Total liabilities and equity	$ 12,111,819	—	1,980,032	23,642	14,115,493

Condensed Consolidating Balance Sheet
December 31, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 17,568	—	14,042	—	31,610
Accounts receivable, net	28,442	—	1,240	—	29,682
Intercompany receivables	3,193	—	64,139	(67,332)	—
Accrued revenue	261,960	—	—	—	261,960
Derivative instruments	73,022	—	—	—	73,022
Other current assets	5,784	—	529	—	6,313
Total current assets	389,969	—	79,950	(67,332)	402,587
Property and equipment:					
Natural gas properties, at cost (successful efforts method):					
Unproved properties	2,331,173	—	—	—	2,331,173
Proved properties	9,726,957	—	—	(177,286)	9,549,671
Water handling and treatment systems	—	—	744,682	—	744,682
Gathering systems and facilities	17,929	—	1,705,839	—	1,723,768
Other property and equipment	41,231	—	—	—	41,231
	12,117,290	—	2,450,521	(177,286)	14,390,525
Less accumulated depletion, depreciation, and amortization	(2,109,136)	—	(254,642)	—	(2,363,778)
Property and equipment, net	10,008,154	—	2,195,879	(177,286)	12,026,747
Derivative instruments	1,731,063	—	—	—	1,731,063
Investments in subsidiaries	(420,429)	—	—	420,429	—
Contingent acquisition consideration	194,538	—	—	(194,538)	—
Other assets, net	21,087	—	74,066	—	95,153
Total assets	$ 11,924,382	—	2,349,895	(18,727)	14,255,550
Liabilities and Equity					
Current liabilities:					
Accounts payable	$ 21,648	—	16,979	—	38,627
Intercompany payable	64,139	—	3,193	(67,332)	—
Accrued liabilities	332,162	—	61,641	—	393,803
Revenue distributions payable	163,989	—	—	—	163,989
Derivative instruments	203,635	—	—	—	203,635
Other current liabilities	17,134	—	200	—	17,334
Total current liabilities	802,707	—	82,013	(67,332)	817,388
Long-term liabilities:					
Long-term debt	3,854,059	—	849,914	—	4,703,973
Deferred income tax liability	950,217	—	—	—	950,217
Contingent acquisition consideration	—	—	194,538	(194,538)	—
Derivative instruments	234	—	—	—	234
Other liabilities	54,540	—	620	—	55,160
Total liabilities	5,661,757	—	1,127,085	(261,870)	6,526,972
Equity:					
Stockholders' equity:					
Partners' capital	—	—	1,222,810	(1,222,810)	—
Common stock	3,149	—	—	—	3,149
Additional paid-in capital	5,299,481	—	—	—	5,299,481
Accumulated earnings	959,995	—	—	—	959,995
Total stockholders' equity	6,262,625	—	1,222,810	(1,222,810)	6,262,625
Noncontrolling interest in consolidated subsidiary	—	—	—	1,465,953	1,465,953
Total equity	6,262,625	—	1,222,810	243,143	7,728,578
Total liabilities and equity	$ 11,924,382	—	2,349,895	(18,727)	14,255,550

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2014, 2015, and 2016

Condensed Consolidating Statement of Operations and Comprehensive Income
Year Ended December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 1,301,349	—	—	—	1,301,349
Natural gas liquids sales	328,323	—	—	—	328,323
Oil sales	107,080	—	—	—	107,080
Gathering, compression, and water handling and treatment	20,284	—	25,178	(23,387)	22,075
Marketing	53,604	—	—	—	53,604
Commodity derivative fair value gains	868,201	—	—	—	868,201
Gain on sale of assets	40,000	—	—	—	40,000
Other income	143	—	—	(143)	—
Total revenue and other	2,718,984	—	25,178	(23,530)	2,720,632
Operating expenses:					
Lease operating	29,341	—	—	—	29,341
Gathering, compression, processing, and transportation	480,367	—	4,460	(23,414)	461,413
Production and ad valorem taxes	85,945	—	1,973	—	87,918
Marketing	103,435	—	—	—	103,435
Exploration	27,893	—	—	—	27,893
Impairment of unproved properties	15,198	—	—	—	15,198
Depletion, depreciation, and amortization	471,372	—	6,524	—	477,896
Accretion of asset retirement obligations	1,271	—	—	—	1,271
General and administrative	212,316	—	4,333	(116)	216,533
Total operating expenses	1,427,138	—	17,290	(23,530)	1,420,898
Operating income	1,291,846	—	7,888	—	1,299,734
Other expenses:					
Interest	(159,585)	—	(466)	—	(160,051)
Loss on early extinguishment of debt	(20,386)	—	—	—	(20,386)
Equity in net income of subsidiaries	5,174	—	—	(5,174)	—
Total other expenses	(174,797)	—	(466)	(5,174)	(180,437)
Income from continuing operations before income taxes and discontinued operations	1,117,049	—	7,422	(5,174)	1,119,297
Provision for income tax expense	(445,672)	—	—	—	(445,672)
Income from continuing operations	671,377	—	7,422	(5,174)	673,625
Discontinued operations:					
Income from sale of discontinued operations, net of income taxes	2,210	—	—	—	2,210
Net income and comprehensive income including noncontrolling interest	673,587	—	7,422	(5,174)	675,835
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	2,248	2,248
Net income and comprehensive income attributable to Antero Resources Corporation	$ 673,587	—	7,422	(7,422)	673,587

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2014, 2015, and 2016

Condensed Consolidating Statement of Operations and Comprehensive Income
Year Ended December 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 1,039,892	—	—	—	1,039,892
Natural gas liquids sales	264,483	—	—	—	264,483
Oil sales	70,753	—	—	—	70,753
Gathering, compression, and water handling and treatment	6,651	—	299,787	(284,438)	22,000
Marketing	176,229	—	—	—	176,229
Commodity derivative fair value gains	2,381,501	—	—	—	2,381,501
Other income	4,594	—	—	(4,594)	—
Total revenue and other	3,944,103	—	299,787	(289,032)	3,954,858
Operating expenses:					
Lease operating	36,132	—	33,283	(33,404)	36,011
Gathering, compression, processing, and transportation	852,573	—	25,305	(218,517)	659,361
Production and ad valorem taxes	77,074	—	1,251	—	78,325
Marketing	299,062	—	—	—	299,062
Exploration	3,846	—	—	—	3,846
Impairment of unproved properties	104,321	—	—	—	104,321
Depletion, depreciation, and amortization	641,860	—	67,903	—	709,763
Accretion of asset retirement obligations	1,655	—	—	—	1,655
General and administrative	190,712	—	43,968	(983)	233,697
Contract termination and rig stacking	38,531	—	—	—	38,531
Accretion of contingent acquisition consideration	—	—	3,333	(3,333)	—
Total operating expenses	2,245,766	—	175,043	(256,237)	2,164,572
Operating income	1,698,337	—	124,744	(32,795)	1,790,286
Other income (expenses):					
Interest	(228,568)	—	(5,832)	—	(234,400)
Equity in net income of subsidiaries	47,485	—	—	(47,485)	—
Total other expenses	(181,083)	—	(5,832)	(47,485)	(234,400)
Income before income taxes	1,517,254	—	118,912	(80,280)	1,555,886
Provision for income tax expense	(575,890)	—	—	—	(575,890)
Net income and comprehensive income including noncontrolling interest	941,364	—	118,912	(80,280)	979,996
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	38,632	38,632
Net income and comprehensive income attributable to Antero Resources Corporation	$ 941,364	—	118,912	(118,912)	941,364

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2014, 2015, and 2016

Condensed Consolidating Statement of Operations and Comprehensive Income (Loss)
Year Ended December 31, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenue and other:					
Natural gas sales	$ 1,260,750	—	—	—	1,260,750
Natural gas liquids sales	432,992	—	—	—	432,992
Oil sales	61,319	—	—	—	61,319
Gathering, compression, and water handling and treatment	—	—	586,352	(573,391)	12,961
Marketing	393,049	—	—	—	393,049
Commodity derivative fair value losses	(514,181)	—	—	—	(514,181)
Gain on sale of assets	93,776	—	3,859	—	97,635
Other income	18,324	—	—	(18,324)	—
Total revenue and other	1,746,029	—	590,211	(591,715)	1,744,525
Operating expenses:					
Lease operating	50,651	—	136,387	(136,948)	50,090
Gathering, compression, processing, and transportation	1,146,221	—	28,097	(291,480)	882,838
Production and ad valorem taxes	69,485	—	(2,897)	—	66,588
Marketing	499,343	—	—	—	499,343
Exploration	6,862	—	—	—	6,862
Impairment of unproved properties	162,935	—	—	—	162,935
Depletion, depreciation, and amortization	710,012	—	99,861	—	809,873
Accretion of asset retirement obligations	2,473	—	—	—	2,473
General and administrative	186,672	—	54,163	(1,511)	239,324
Accretion of contingent acquisition consideration	—	—	16,489	(16,489)	—
Total operating expenses	2,834,654	—	332,100	(446,428)	2,720,326
Operating income (loss)	(1,088,625)	—	258,111	(145,287)	(975,801)
Other income (expenses):					
Equity in earnings of unconsolidated affiliate	—	—	485	—	485
Interest	(232,455)	—	(21,893)	796	(253,552)
Loss on early extinguishment of debt	(16,956)	—	—	—	(16,956)
Equity in net income of subsidiaries	(7,156)	—	—	7,156	—
Total other expenses	(256,567)	—	(21,408)	7,952	(270,023)
Income (loss) before income taxes	(1,345,192)	—	236,703	(137,335)	(1,245,824)
Provision for income tax benefit	496,376	—	—	—	496,376
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(848,816)	—	236,703	(137,335)	(749,448)
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	99,368	99,368
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (848,816)	—	236,703	(236,703)	(848,816)

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 992,930	—	5,333	—	998,263
Cash flows used in investing activities:					
Additions to proved properties	(64,066)	—	—	—	(64,066)
Additions to unproved properties	(777,422)	—	—	—	(777,422)
Drilling and completion costs	(2,477,150)	—	—	—	(2,477,150)
Additions to water handling and treatment systems	(196,675)	—	—	—	(196,675)
Additions to gathering systems and facilities	(543,196)	—	(14,841)	—	(558,037)
Additions to other property and equipment	(13,218)	—	—	—	(13,218)
Change in other assets	(2,928)	—	(154)	—	(3,082)
Net distributions from guarantor subsidiary	115,000	—	—	(115,000)	—
Distributions from non-guarantor subsidiary	332,500	—	—	(332,500)	—
Net cash used in investing activities	(3,627,155)	—	(14,995)	(447,500)	(4,089,650)
Cash flows provided by (used in) financing activities:					
Issuance of common units by Antero Midstream Partners LP	—	—	1,087,224	—	1,087,224
Issuance of senior notes	1,102,500	—	—	—	1,102,500
Repayment of senior notes	(260,000)	—	—	—	(260,000)
Borrowings (repayments) on bank credit facility, net.	1,837,000	115,000	(510,000)	—	1,442,000
Make-whole premium on debt extinguished	(17,383)	—	—	—	(17,383)
Payments of deferred financing costs	(26,673)	—	(4,870)	—	(31,543)
Distributions	—	(115,000)	(332,500)	447,500	—
Employee tax withholding for settlement of equity compensation awards	(142)	—	—	—	(142)
Other	(2,777)	—	—	—	(2,777)
Net cash provided by (used in) financing activities.	2,632,525	—	239,854	447,500	3,319,879
Net decrease in cash and cash equivalents	(1,700)	—	230,192	—	228,492
Cash and cash equivalents, beginning of period	17,487	—	—	—	17,487
Cash and cash equivalents, end of period	$ 15,787	—	230,192	—	245,979

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 853,548	—	195,059	(32,795)	1,015,812
Cash flows used in investing activities:					
Additions to unproved properties	(198,694)	—	—	—	(198,694)
Drilling and completion costs	(1,684,077)	—	—	32,795	(1,651,282)
Additions to water handling and treatment systems	(80,064)	—	(50,987)	—	(131,051)
Additions to gathering systems and facilities	(40,285)	—	(320,002)	—	(360,287)
Additions to other property and equipment	(6,595)	—	—	—	(6,595)
Change in other assets	2,570	—	7,180	—	9,750
Net distributions to guarantor subsidiary	(115,000)	—	—	115,000	—
Distributions from non-guarantor subsidiary	73,119	—	—	(73,119)	—
Proceeds from contribution of assets to non-guarantor subsidiary	801,116	—	—	(801,116)	—
Proceeds from asset sales	40,000	—	—	—	40,000
Net cash used in investing activities	(1,207,910)	—	(363,809)	(726,440)	(2,298,159)
Cash flows provided by (used in) financing activities:					
Issuance of common stock	537,832	—	—	—	537,832
Issuance of common units by Antero Midstream Partners LP	—	—	240,703	—	240,703
Issuance of senior notes	750,000	—	—	—	750,000
Borrowings (repayments) on bank credit facility, net	(908,000)	(115,000)	620,000	—	(403,000)
Payments of deferred financing costs	(15,234)	—	(2,059)	—	(17,293)
Distributions	—	115,000	(908,364)	759,235	(34,129)
Employee tax withholding for settlement of equity compensation awards	(4,625)	—	(4,806)	—	(9,431)
Other	(4,808)	—	(33)	—	(4,841)
Net cash provided by (used in) financing activities	355,165	—	(54,559)	759,235	1,059,841
Net decrease in cash and cash equivalents	803	—	(223,309)	—	(222,506)
Cash and cash equivalents, beginning of period	15,787	—	230,192	—	245,979
Cash and cash equivalents, end of period	$ 16,590	—	6,883	—	23,473

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2014, 2015, and 2016

Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 1,007,140	—	378,607	(144,491)	1,241,256
Cash flows used in investing activities:					
Additions to proved properties	(134,113)	—	—	—	(134,113)
Additions to unproved properties	(611,631)	—	—	—	(611,631)
Drilling and completion costs	(1,472,250)	—	—	144,491	(1,327,759)
Additions to water handling and treatment systems	32	—	(188,220)	—	(188,188)
Additions to gathering systems and facilities	(2,944)	—	(228,100)	—	(231,044)
Additions to other property and equipment	(2,694)	—	—	—	(2,694)
Investments in unconsolidated affiliates	—	—	(75,516)	—	(75,516)
Change in other assets	304	—	3,673	—	3,977
Net distributions from subsidiaries	107,364	—	—	(107,364)	—
Proceeds from asset sales	161,830	—	10,000	—	171,830
Net cash used in investing activities	(1,954,102)	—	(478,163)	37,127	(2,395,138)
Cash flows provided by financing activities:					
Issuance of common stock	1,012,431	—	—	—	1,012,431
Issuance of common units by Antero Midstream Partners LP	—	—	65,395	—	65,395
Sale of common units in Antero Midstream Partners LP by Antero Resources Corporation	178,000	—	—	—	178,000
Issuance of senior notes	600,000	—	650,000	—	1,250,000
Repayment of senior notes	(525,000)	—	—	—	(525,000)
Repayments on bank credit facility, net	(267,000)	—	(410,000)	—	(677,000)
Make-whole premium on debt extinguished	(15,750)	—	—	—	(15,750)
Payments of deferred financing costs	(8,324)	—	(10,435)	—	(18,759)
Distributions	—	—	(182,446)	107,364	(75,082)
Employee tax withholding for settlement of equity compensation awards	(21,260)	—	(5,635)	—	(26,895)
Other	(5,157)	—	(164)	—	(5,321)
Net cash provided by financing activities	947,940	—	106,715	107,364	1,162,019
Net increase (decrease) in cash and cash equivalents	978	—	7,159	—	8,137
Cash and cash equivalents, beginning of period	16,590	—	6,883	—	23,473
Cash and cash equivalents, end of period	$ 17,568	—	14,042	—	31,610

(18) Quarterly Financial Information (Unaudited)

The Company's quarterly consolidated financial information for the years ended December 31, 2015 and 2016 is summarized in the following tables (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, 2015:				
Total operating revenues	$ 1,229,687	$ 376,714	$ 1,443,335	$ 905,122
Total operating expenses	529,993	540,463	502,220	591,896
Operating income (loss)	699,694	(163,749)	941,115	313,226
Net income (loss) and comprehensive income (loss) including noncontrolling interest	399,171	(139,483)	544,734	175,574
Net income attributable to noncontrolling interest	4,740	5,890	10,892	17,110
Net income (loss) attributable to Antero Resources Corporation	394,431	(145,373)	533,842	158,464
Earnings (loss) per common share—basic	$ 1.49	$ (0.52)	$ 1.93	$ 0.57
Earnings (loss) per common share—assuming dilution	$ 1.49	$ (0.52)	$ 1.93	$ 0.57

	First quarter	Second quarter	Third quarter	Fourth quarter
Year Ended December 31, 2016:				
Total operating revenues	$ 721,004	$ (249,198)	$ 1,116,503	$ 156,216
Total operating expenses	642,255	640,675	649,171	788,225
Operating income (loss)	78,749	(889,873)	467,332	(632,009)
Net income (loss) and comprehensive income (loss) including noncontrolling interest	10,650	(575,490)	268,196	(452,804)
Net income attributable to noncontrolling interest	15,705	20,754	29,941	32,968
Net income (loss) attributable to Antero Resources Corporation	(5,055)	(596,244)	238,255	(485,772)
Earnings (loss) per common share	$ (0.02)	$ (2.12)	$ 0.78	$ (1.55)
Earnings (loss) per common share—diluted	$ (0.02)	$ (2.12)	$ 0.77	$ (1.55)

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

The following is supplemental information regarding the Company's consolidated oil and gas producing activities. The amounts shown include the Company's net working interests in all of its oil and gas properties.

(a) Capitalized Costs Relating to Oil and Gas Producing Activities

(In thousands)	Year ended December 31, 2015	2016
Proved properties	$ 8,211,106	9,549,671
Unproved properties	1,996,081	2,331,173
	10,207,187	11,880,844
Accumulated depletion and depreciation	(1,415,005)	(2,089,500)
Net capitalized costs	$ 8,792,182	9,791,344

(b) Costs Incurred in Certain Oil and Gas Activities

(In thousands)	Year ended December 31, 2014	2015	2016
Acquisition costs:			
Proved property	$ 64,066	—	134,113
Unproved property	777,422	198,694	611,631
Development costs	1,536,193	1,039,301	1,000,903
Exploration costs	940,957	611,981	326,856
Total costs incurred	$ 3,318,638	1,849,976	2,073,503

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

(In thousands)	Year ended December 31, 2014	2015	2016
Revenues	$ 1,736,752	1,375,128	1,755,061
Operating expenses:			
Production expenses	578,672	773,697	999,516
Exploration expenses	27,893	3,846	6,862
Depletion and depreciation	418,744	614,700	700,274
Impairment of unproved properties	15,198	104,321	162,935
Results of operations before income tax expense	696,245	(121,436)	(114,526)
Income tax (expense) benefit	(263,126)	45,497	43,334
Results of operations	$ 433,119	(75,939)	(71,192)

(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, 2014, 2015, and 2016 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 crude oil, condensate, and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The Company estimates proved reserves using average prices received for the previous 12 months.

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

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved reserves:				
December 31, 2013	6,753	137	10	7,632
Revisions	(1,025)	(6)	— (a)	(1,054)
Extensions, discoveries and other additions	5,095	206	19	6,444
Purchases of reserves	29	—	—	29
Production	(317)	(7)	(1)	(368)
December 31, 2014	10,535	330	28	12,683
Revisions	(2,816)	176	(8)	(1,801)
Extensions, discoveries and other additions	2,253	97	8	2,878
Production	(439)	(16)	(2)	(545)
December 31, 2015	9,533	587	26	13,215
Revisions	(2,069)	275	3	(404)
Extensions, discoveries and other additions	1,990	99	9	2,637
Production	(505)	(27)	(2)	(676)
Purchases of reserves	475	23	2	624
Sales of reserves in place	(10)	—	—	(10)
December 31, 2016	9,414	957	38	15,386

(a) Less than 1.0.

	Natural gas (Bcf)	NGLs (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2014	3,285	80	6	3,803
December 31, 2015	3,627	360	8	5,838
December 31, 2016	4,426	401	13	6,914
Proved undeveloped reserves:				
December 31, 2014	7,250	250	22	8,880
December 31, 2015	5,906	227	18	7,377
December 31, 2016	4,988	556	25	8,472

Significant items included in the categories of proved developed and undeveloped reserve changes for the years 2014, 2015, and 2016 in the above table include the following:

2014 Changes in Reserves

- 2014—Extensions, discoveries, and other additions during 2014 of 6,444 Bcfe were added through exploratory and developmental drilling in the Marcellus and Utica Shales.
- Purchases of 29 Bcfe relate to 5 horizontal producing wells acquired as part of the Company's leasehold acquisition efforts.
- Positive performance revisions of 361 Bcfe relate to improved well performance from shorter stage length completions.
- Downward revisions of 1,417 Bcfe due were due to the reclassification of 191 dry gas locations to the probable category because they were no longer expected to be drilled within five years of initial booking.

- Upward price revisions of 2 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the prices for NGLs and oil.

2015 Changes in Reserves

- Extensions, discoveries, and other additions of 2,878 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales.
- Positive revisions of 1,091 Bcfe due to partial ethane recovery is a result of changing from ethane rejection at December 31, 2014 to partial ethane recovery in 2015. In 2015, the Company began ethane recovery and changed its underlying production assumptions to the recovery of approximately 11,500 gross barrels per day of ethane at December 31, 2015.
- Negative performance revisions of 358 Bcfe resulted from the revised statistical analysis of reserves based on actual production results.
- Negative revisions of 2,332 Bcfe were due to the SEC 5-year development rule because the Company no longer expected certain locations in the eastern portion of its Marcellus acreage containing primarily dry gas to be developed within five years.
- Negative revisions of 202 Bcfe were due to the decreases in prices for natural gas, NGLs, and oil.

2016 Changes in Reserves

- Extensions, discoveries and other additions of 2,637 Bcfe resulted from delineation and development drilling in both the Marcellus and Utica Shales, which was aided in 2016 by longer laterals than in previous years and the utilization of advanced completion techniques.
- Purchases of 624 Bcfe relate to the acquisition of developed and undeveloped leasehold acreage in both the Marcellus and Utica Shales.
- Positive revisions of 1,359 Bcfe are due to an increase in our actual and assumed future ethane recovery rate based on existing sales contracts for ethane.
- Positive performance revisions of 762 Bcfe primarily relate to improved well performance.
- Negative revisions of 2,478 Bcfe were due to the impact of the SEC 5-year development rule. Due to the SEC 5-year development rule, these primarily dry gas reserves were displaced by our current development plan targeting more liquids-rich areas in our portfolio which have better economic returns.
- Negative revisions of 47 Bcfe were due to the decreases in prices for natural gas, NGLs, and oil.
- A negative revision of 10 Bcfe was related to our sale of producing and non-producing leasehold in Pennsylvania.

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

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

(in millions)	Year ended December 31, 2014	2015	2016
Future cash inflows	$ 63,632	35,179	36,800
Future production costs	(21,722)	(17,393)	(21,275)
Future development costs	(8,212)	(5,217)	(3,902)
Future net cash flows before income tax	33,698	12,569	11,623
Future income tax expense	(10,726)	(1,708)	(1,042)
Future net cash flows	22,972	10,861	10,581
10% annual discount for estimated timing of cash flows	(15,337)	(7,628)	(7,294)
Standardized measure of discounted future net cash flows	$ 7,635	3,233	3,287

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

December 31, 2014	$ 5.02
December 31, 2015	$ 2.66
December 31, 2016	$ 2.39

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

(in millions)	Year ended December 31, 2014	2015	2016
Sales of oil and gas, net of productions costs	$ (1,158)	(601)	(756)
Net changes in prices and production costs	(184)	(9,416)	(1,540)
Development costs incurred during the period	564	769	733
Net changes in future development costs	(102)	671	212
Extensions, discoveries and other additions	5,759	861	673
Acquisitions	42	—	66
Divestitures	—	—	(7)
Revisions of previous quantity estimates	(828)	(1,167)	461
Accretion of discount	600	1,132	363
Net change in income taxes	(2,198)	3,284	12
Other changes	630	65	(163)
Net increase (decrease)	3,125	(4,402)	54
Beginning of year	4,510	7,635	3,233
End of year	$ 7,635	3,233	3,287

(20) Subsequent Events

On February 6, 2017, Antero Midstream formed a joint venture (the "Joint Venture") to develop processing assets in Appalachia with MarkWest Energy Partners, L.P. ("MarkWest"), a wholly owned subsidiary of MPLX, L.P. Antero Midstream and MarkWest will each own a 50% interest in the Joint Venture and MarkWest will operate the Joint Venture assets. The Joint Venture assets will consist of processing plants in West Virginia and a one-third interest in a recently commissioned MarkWest fractionator in Ohio.

In conjunction with the formation of the Joint Venture, on February 10, 2017 Antero Midstream issued 6,900,000 common units, including the underwriters' purchase option, generating net proceeds of approximately $223 million. Antero Midstream used the net proceeds to fund the initial $155 million contribution to the Joint Venture, repay outstanding borrowings under its credit facility, and for general partnership purposes.

CORPORATE INFORMATION

DIRECTORS

ROBERT J. CLARK
Audit Committee,
Compensation Committee
and Nominating Committee

RICHARD W. CONNOR
Audit Committee Chairman
and Nominating Committee

BENJAMIN A. HARDESTY
Audit Committee,
Compensation Committee
and Nominating Committee

PETER R. KAGAN
Nominating Committee

W. HOWARD KEENAN, JR.
Nominating Committee

JAMES R. LEVY
Compensation Committee

MANAGEMENT

PAUL M. RADY
Chairman and Chief Executive Officer

GLEN C. WARREN, JR.
President, Chief Financial Officer
and Director

MICHAEL N. KENNEDY
Senior Vice President—Finance

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

KEVIN J. KILSTROM
Senior Vice President—Production

BRIAN A. KUHN
Senior Vice President—Land

MARK D. MAUZ
Senior Vice President—Gathering,
Marketing and Transportation

WARD D. McNEILLY
Senior Vice President—Reserves,
Planning and Midstream

STEVEN M. WOODWARD
Senior Vice President—
Business Development

J. KEVIN ELLIS
Vice President— Government Relations

JOHN GIANNAULA
Vice President—Human Resources
and Administration

W. CHAD GREEN
Vice President—Finance

PAUL L. KOVACH
Vice President—Geoscience

AARON S. G. MERRICK
Vice President—Information Technology

WILLIAM J. PIERINI
Vice President—Land

TROY R. ROACH
Vice President—Health, Safety
and Environment

YVETTE K. SCHULTZ
General Counsel
and Vice President—Legal

CHRISTOPHER W. TREML
Vice President—Land

ROBERT S. TUCKER
Vice President—Geology

K. PHIL YOO
Vice President—Accounting,
Chief Accounting Officer
and Corporate Controller

INVESTOR RELATIONS

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AND TRUST COMPANY, LLC
6201 15th Avenue
Brooklyn, New York 11219
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INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP Denver, Colorado

SHAREHOLDER INFORMATION

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

CORPORATE HEADQUARTERS

ANTERO RESOURCES CORPORATION
1615 Wynkoop Street
Denver, Colorado 80202

FORWARD-LOOKING STATEMENTS

The 2016 Annual Report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Such forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond Antero's control. All statements, other than historical facts included in this annual report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. All forward-looking statements speak only as of the date of this annual report. Although Antero believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering, processing, transportation and sale of natural gas, NGLs and oil. These risks include, but are not limited to, commodity price volatility and low commodity prices, inflation, availability of drilling and production equipment and services, environmental risks, drilling 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 flow and access to capital, the timing of development expenditures, and the other risks described under the heading "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2016.


Antero
Resources